Enabling concentrating solar power in Australia: An investigation of the benefits and potential role of concentrating solar power and non-conventional fuel hybrid plants in Australia's transition to a low-carbon energy future

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STATEMENT OF ORIGINAL AUTHORSHIP

I certify that the work in this thesis has not previously been submitted for a degree and nor has it been submitted as part of the requirements for a degree.

I also certify that the thesis is an original piece of research written by me, except where noted in the text. Any help that I have received in my research work and in the preparation of the thesis itself has been acknowledged. In addition, I certify that all information sources and literature used are indicated in the thesis.

Signature of candidate:

Juergen Heinz Martin Peterseim

I dedicate this thesis to love and hope:

love for my wife Anja and my children Lola and Leon, and

hope for a bright future for concentrating solar power in Australia.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF PUBLICATIONS

Relevant publications:

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LIST OF ABBREVIATIONS

AHP	analytical hierarchy process
ASTRI	Australian solar thermal research initiative
AU$	Australian dollar
b	billion
CapEx	capital expenditure
CO_2	carbon dioxide
CSP	concentrating solar power
DNI	direct normal irradiance
EfB	energy from biomass
EfW	energy from waste
EPC	engineering, procurement and construction
GIS	geographic information system
GWh	gigawatt hour
h	hours
HRSG	heat recovery steam generator
ISCC	integrated solar combined cycle
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
m	million
MLP	multi-level perspective
MSW	municipal solid waste
MW	megawatt
MWh	megawatt hour
MWth	Megawatt thermal
NEM	national electricity market
OpEx	operational expenditure
PPA	power purchase agreement
PV	photovoltaic
R&D	research and development
RDF	refused derived fuels
RECs	renewable energy certificates
RET	renewable energy target
SEGS	solar energy generation systems
SNM	strategic niche management
SRF	solid recovered fuels
t	tonnes
t/h	tonnes per hour
TES	thermal energy storage
TWh	terrawatt hour
US$	U.S. dollar

ABSTRACT

After decades of stability the Australian electricity market is undergoing changes. Current government targets aim to reduce greenhouse gas emissions by 5% and raise renewable electricity production to 45 TWh by 2020. In addition, increases to natural gas prices, aging generation assets and falling electricity demand have had an impact in recent years.

Uncertainties exist around current policies, including the carbon pricing mechanism and the renewable energy target, but in light of Australian and international ambitions to lower greenhouse gas emissions the deployment of renewable energy technologies is essential. In recent years wind and photovoltaic installations have shown the highest renewable energy growth rates while concentrating solar power has struggled, despite Australia having some of the best natural resources for concentrating solar power in the world and some selected government funding. Reasons for the slow uptake include the comparatively high cost and lack of financial incentives. While technology costs are expected to decrease by up to 40% by 2020 through deployment as well as research and development, other cost reduction options have to be identified to promote short-term implementation in electricity markets such as Australia where the wholesale cost is low. To overcome the cost problem and to address other relevant implementation barriers this research analyses the hybridisation of concentrating solar power with biomass and waste feedstocks.

The results of this research include:

- a recommendation for a categorisation system for CSP hybrid plants based on the degree of interconnection of the plant components
- the availability of combined resources to generate up to 33.5 TWh per year and abate 27 million tonnes CO_2 annually
- an analysis of the most suitable CSP technologies for hybridisation
- a technology comparison showing CSP cost reductions through hybridisation of up to 40%
- the identification of cost differences of up to 31% between different hybrid concepts
- an analysis showing that the current economic and policy settings are the most significant implementation barriers
- two case studies with different biomass and waste feedstocks requiring power purchase agreements of AU$ 100-155/MWh.

Based on the various benefits of concentrating solar power hybrid plants, this research analyses the potential role of this technological pairing in Australia's transition to a low carbon energy future. The research concludes that concentrating solar power hybrid plants, not only hybridised with biomass and waste feedstocks, can immediately enable a lower cost deployment of concentrating solar power facilities in Australia. The technology, deployment and operation of the first hybrid installations would provide market participants with valuable lessons and would have the potential to reconfigure the electricity market towards more sustainable generation. This could help promote the development of future low-cost concentrating solar power plants in Australia.

FOREWORD

When I started considering a PhD candidature in 2010 I already had a few potential topics in mind that derived from observations I had made since entering the energy business in 2003. I worked as an industrial engineer in several areas, including project management and business development, for the German boiler design companies La Mont-Kessel GmbH & Co. KG and ERK Eckrohrkessel GmbH. This allowed me to develop a detailed understanding of current issues with solid, liquid and gaseous fuel fired water tube boiler systems, and of their impact on power plant efficiency, reliability and cost. My early focus was on energy from biomass and from waste systems as well as work on compact boiler and heat exchanger systems. After moving to Australia in 2007 I continued work in these fields but also expanded into heat recovery and natural gas fired boilers.

The good resource for solar energy in Australia, and my interest in Rankine cycle systems, shifted my attention to concentrating solar power. The technology was immediately appealing due to its futuristic appearance, its low carbon intensity, and the availability of mature equipment for most of the plant. In late 2010 I was awarded a UTS scholarship and since commencing this research in March 2011 my interest in concentrating solar power has continued to grow. The work I have done for my PhD has enabled me to expand my knowledge not only through theoretical work, such as a literature review and thermo-economic modelling, but also through the exchange of ideas and cooperation with industry partners, both those I had known previously and others I have met during the last three years.

I sincerely hope that this thesis will contribute to the deployment of concentrating solar power plants in Australia and I am looking forward to further engaging with the technology for the foreseeable future.

1 INTRODUCTION

After decades of stability the Australian electricity market is undergoing changes due to a recently introduced carbon pricing mechanism, slowly rising renewable energy penetration, energy efficiency measures, rising natural gas prices, falling electricity demand in recent years, and an aging fleet of coal fired power plants. Despite current uncertainties around the carbon pricing and the renewable energy mechanisms the market is likely to continue its transition due to the increasing certainty on anthropogenic climate change and the need to respond to it, e.g. existing greenhouse gas abatement targets for 2020 and 2050, continuously falling costs for renewable energy technologies and rising natural gas prices.

In 2010–11 10% of Australia's electricity came from renewable sources. This was significantly below the world average of 20% but the country does have the resources, such as wind, solar, biomass, and sites suitable for hydro and tidal generation, to be a leader in renewable energy. Of particular interest for this research is solar radiation, for which Australia has one of the best resources in the world. However, renewable energy uptake has been slow in the past as the country has vast and easily accessible fossil fuel resources, which has led to low wholesale electricity prices, particularly from coal fired power generation. In such an economic environment renewable energy technologies struggle to enter a market where fossil fuels are subsidised, externality costs are not fully accounted for, and renewable energy incentives are limited. This is a particular problem for concentrating solar power (CSP) which is currently a more costly alternative than wind and photovoltaic (PV) power generation. However, CSP is of strategic importance for Australia as it is a renewable energy technology with proven energy storage capabilities that can balance other intermittent renewable energy technologies, such as wind and PV. The reason for the higher CSP cost is its limited global deployment of 4 GWe in 2013 compared to 128 GW for PV and 321 GWe for wind. Therefore, the technology providers have less experience and access to economies of scale. While there are utility-scale reference plants in operation, the industry is still at an early stage of technology implementation.

A variety of different CSP technologies exist. Parabolic trough plants are the most mature but their cycle efficiency is limited. The first commercial plants commenced operations in the late 1970s to early 1980s and current installations reach capacities of 280 MWe with many units having thermal energy storage (TES). Commercial solar tower and Fresnel plants entered the market some 20 years later and have a higher efficiency and cost reduction potential but their development has not yet reached the maturity of parabolic trough systems. However, current solar tower installations reach capacities of 130 MWe. They are the CSP technology with the largest TES capacities, having a plant with 15 h TES capacity in operation and a plant with a 17.5 h capacity about to be constructed. Currently, operational Fresnel plant capacities are limited to 30 MWe but a 2x 125 MWe unit is under construction. Unlike the aforementioned CSP technologies, TES has not been incorporated in Fresnel plants but is being investigated. Currently, both solar tower and Fresnel technologies are demonstrating their technical and economic capabilities, and if the recently and soon-to-be-commissioned plants meet industry expectations both will gain a larger market share.

Technology improvements and continuous deployment are expected to lower plant costs by up to 40% by 2020 but this estimate involves uncertainties around the availability of government support. Moreover, learning from technology deployment, and incorporating the resulting developments into new plants is a time-consuming process. One option to fast-track the 2020 CSP cost reduction target is the hybridisation of CSP with other energy sources. In other countries first reference plants with up to 75 MWe CSP energy equivalent already operate successfully with natural gas, coal and biomass. The success of these plants confirms the cost benefits that CSP hybrids provide. In Australia one small 9.3 MWth CSP retrofit is already operational at the 2 GWe Liddell coal-fired power station while another 44 MWe retrofit is under construction at the 750 MWe Kogan Creek power station. Additionally, some new CSP hybrids with natural gas and biomass are being investigated. In the past only two CSP projects have been awarded significant state and federal government funding but the developers could not secure the remaining funds they needed and had to withdraw their proposals, which highlights the cost problem CSP faces in entering the Australian electricity market. The cost of CSP hybrids is lowered relative to CSP-only plants due to the joint use of plant equipment, such as steam turbines and condensers. In addition, hybrid plants involve less financial risk as they can have much smaller capacities than CSP-only plants which if they are to be economically viable, must be large enough to achieve economies-of-scale. In addition lower-cost CSP hybrids also encounter lower social, technical, environmental and policy implementation barriers. Despite these and other benefits the hybridisation of CSP with fossil fuel generation has to be considered carefully to ensure that such plants provide net environmental benefits, are not used to justify the lifetime expansions of old generation assets, and avoid fossil fuel technology lock-in. While acknowledging that project-dependent CSP-fossil fuel hybrids can have a positive net environmental impact, this research investigates CSP hybrids which use energy from biomass (EfB) and from waste (EfW) as such hybrids are a low carbon intensity power generation option which is able to provide the learnings the CSP industry needs while providing energy at a competitive cost with high environmental benefits.

To analyse the potential role CSP–EfB and CSP–EfW hybrid plants can have in Australia's transition to a low-carbon future, a detailed understanding of the available technologies, technical concepts, resources and implementation barriers is required. It is unlikely that one niche technology, such as CSP–EfB and CSP–EfW hybrids, can significantly change the current Australian electricity market towards environmental sustainability. Therefore other CSP hybrid options, described in Section 4.1, are considered as well. To understand the combined CSP, EfB and EfW resources, and to identify the total potential for such hybrids, a detailed geospatial analysis considering various technical, economic and environmental constraints was carried out and the results are presented in Section 4.2. Currently, various technologies are available which can be hybridised in many different ways. Identifying the most suitable CSP technologies for hybridisation, not only with EfB and EfW but also with natural gas and coal plants, is the aim of Section 4.3 while the identification of the currently best high solar share CSP–EfB and CSP–EfW hybrid concepts is the aim of Section 4.4. It has been observed in the current electricity market that the uptake of CSP has so far been very limited and therefore implementation barriers must exist. The process of identifying these barriers and assessing their importance for CSP-only and CSP hybrid plants is discussed in Section 4.5, which also examines the perspectives that the various stakeholders in energy projects have about these barriers. To assess the benefits that CSP–EfB and CSP–EfW hybrid plants can provide in actual situations, two case studies were designed and analysed and the results are shown in Section 4.6. The first case study investigates a CSP–multi-fuel plant in Queensland which uses various biomass and waste feedstocks and the second is on a CSP–single-fuel plant in New South Wales which uses straw as the biomass feedstock.

Based on the various findings in Sections 4.1 to 4.6, Section 4.7 analyses the potential role CSP–EfB and CSP–EfW hybrid plants can play in the implementation of CSP technologies in Australia's low cost wholesale electricity market. To broaden the impact of CSP–EfB and CSP–EfW hybrid concepts, a brief discussion of other CSP hybrid options is provided. The potential role of CSP–EfB and CSP–EfW hybrid plants is analysed with the transition management framework. This framework is well suited as it can support the description and analysis of the various aspects of a transition process. It has been used to describe a variety of transition processes, including energy transition research, in other countries worldwide. The technical integration concepts in this work are widely transferable to other Rankine cycle hybrid systems, and this increases the potential for CSP hybrid plants to contribute to the energy transition.

2 LITERATURE REVIEW

This chapter aims to provide a comprehensive overview of the relevant literature for this research. It covers technologies, economics, policy, and the transition management research framework. This literature review is based on journal papers and reports from reputable agencies but to incorporate the latest developments it also includes online references from institutional sources and technology providers. Without them, an up-to-date view of CSP, EfB and EfW developments is not possible.

2.1 The Australian electricity market

The scientific consensus on anthropogenic climate change is overwhelming (Cook et al. 2013) and according to the fifth assessment by the Intergovernmental Panel on Climate Change the future impact of anthropogenic climate change on the Australian environment and economy is expected to be significant, e.g. ecosystem vulnerability, rainfall changes, higher frequency/intensity of extreme climatic events, and risks to coastal infrastructure and agricultural production (Reisinger et al. 2014). Electricity generation is the largest source of greenhouse gas emissions in Australia (Department of Climate Change and Energy Efficiency 2012) and the support of this industry is essential to lower future greenhouse gas emissions, which is the key contributor to anthropogenic climate change. Various renewable energy resources are available in Australia and these have the potential to provide low greenhouse gas emission electricity.

The Australian electricity market is a concentrated one, with a few vertically integrated companies providing generation, transmission, and distribution capacity. Large capacity centralised power stations dominate the power generation portfolio with only some distributed renewable energy and natural gas fired co- and trigeneration facilities in operation. Three transmission–distribution networks exist: the National Electricity Market (NEM) which stretches along the eastern seaboard from Queensland to South Australia, and the South West Interconnect and North West Interconnect Systems in Western Australia. The NEM covers the majority of population and industry in Australia and is by far the biggest electricity network. Remote developments, such as cities like Alice Springs or mine sites, are powered by off-grid power systems, mostly using natural gas or diesel.

This section provides an introduction into this market by highlighting its current status and the policies in place to meet the targets which have been set for 2020 and for 2050.

2.1.1 Current status

Australia has abundant fossil and renewable energy resources (Bureau of Resources and Energy Economics 2013) but the low cost of fossil fuels, the failure of market prices to reflect external costs, and subsidies to the fossil fuel industry (Riedy 2007) have favoured the use of fossil fuels over renewables. The abundance of Australia's coal resources are reflected in their 69% share of the nation's 2011–12 electricity production of 254.7 TWh (see Figure 1). Historically, coal has had an even higher share, over 75% of annual electricity generation (Australian Bureau of Agricultural and Resource Economics 2011), but the combination of the recently introduced carbon pricing mechanism (Australian Government 2011), falling electricity demand in recent years (pitt&sherry 2014) and the advanced age of the majority of Australia's power stations led to the recent mothballing or closure of some coal fired units, such as 2x 350 MWe units at Tarong power station (Hyslop 2013) and 1,400 MWe Munmorah power station (Harvey 2012), and hence lower annual generation and greenhouse gas emissions. . Figure 2 shows the electricity generation and emission developments in the NEM from June 2006 to December 2013. Figure 3 shows the decrease in greenhouse gas emissions in recent years caused by natural gas and wind generation displacing higher carbon intensity coal fired generation. For the period 2013–14 electricity demand in the NEM is expected to further decrease by 1.3% (Australian Energy Market Operator 2014). Across Australia natural gas fired generation increased in 201-12, and with 20% of annual electricity it was the second-largest fuel source for power generation. Natural gas provided twice as much electricity as all renewable energy sources combined (Bureau of Resources and Energy Economics 2013).

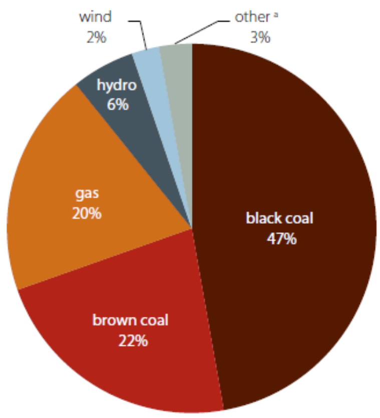

Figure 1: Australia's electricity generation 2011-12 by energy source (Bureau of Resources and Energy Economics 2013); Other includes oil, bioenergy, solar PV, and multi-fuel fired power plants

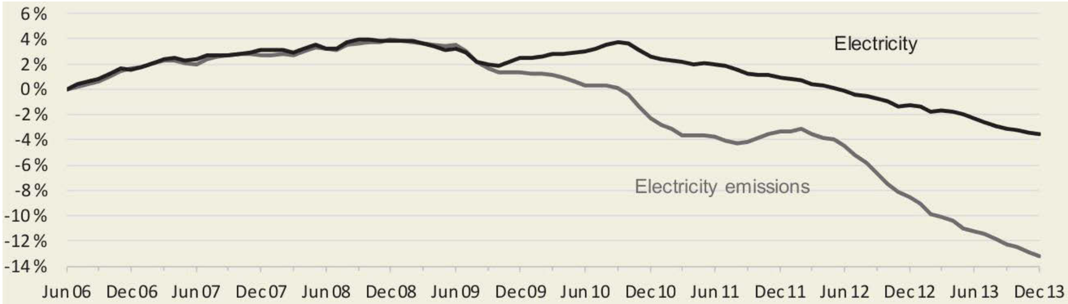

Figure 2: Changes in electricity generation and emissions in the NEM (pitt&sherry 2014)

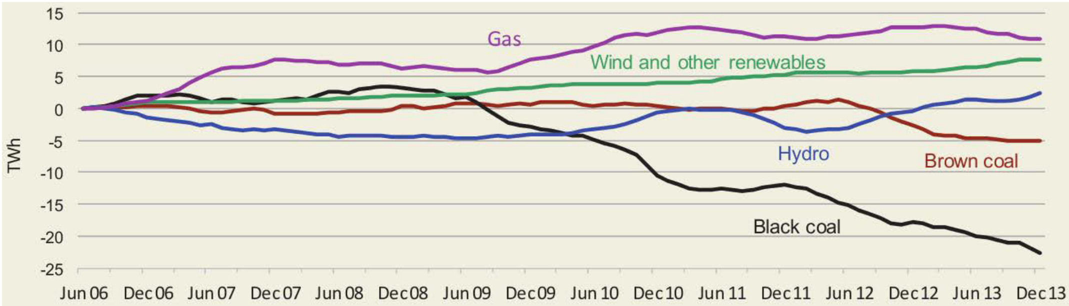

Figure 3: Changes in electricity generation by fuel type in the NEM (pitt&sherry 2014)

Figure 4 shows that the dominant contributor, today and historically, to Australia's 10% annual renewable electricity was hydro power which provided two-thirds of the nation's renewably generated electricity in 2010–11. Wind is the second-most significant source, followed by biomass, biogas and PV (Bureau of Resources and Energy Economics 2013). No commercial CSP plants were operational in 2010–11 and currently only a small CSP boost at the Liddell coal fired power plant is operational. Despite excellent renewable resources, annual renewable electricity generation has increased only moderately since 2001 and in 2011 it was still well below the world average of 20% (International Energy Agency 2013). However, the percentage of electricity from renewable sources in the NEM increased to 14.3% in 2013 (pitt&sherry 2014). National data and a breakdown by source are not yet publicly available for 2013. The strongest renewable energy growth since 2004–05 came from wind and PV with wind generation increasing by 31% and PV generation increasing by 41% (Bureau of Resources and Energy Economics 2013).

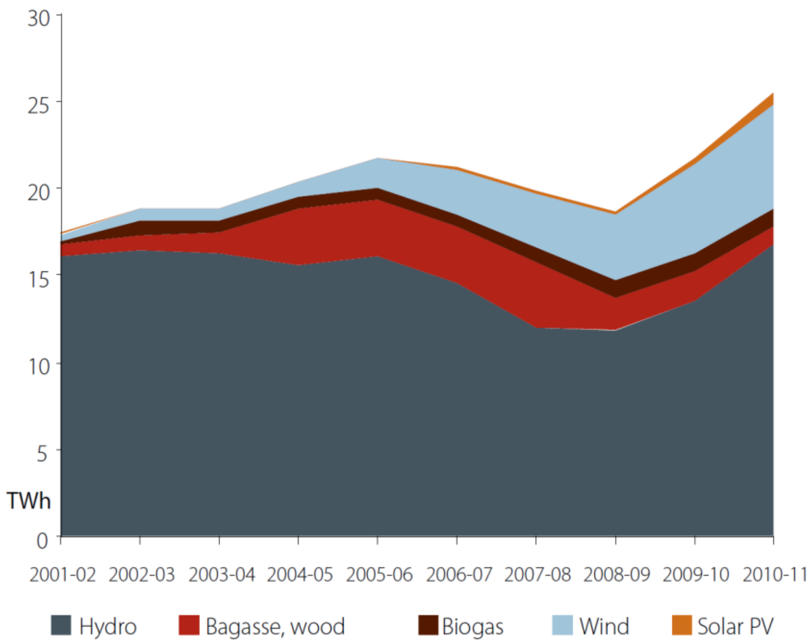

Figure 4: Australian electricity generation from renewable energy (Bureau of Resources and Energy Economics 2013)

A variety of policy, economic, and socio-cultural barriers, which affect not only renewable energy use but also energy efficiency and demand management, are responsible for the comparatively slow uptake of renewable electricity (Byrnes et al. 2013; Dunstan, Ross & Ghiotto 2011; Mckenzie & Howes 2006). While similar barriers exist elsewhere in the world (Moomaw et al. 2011) Australia's abundance of fossil fuels has historically resulted in policy bias against renewable energy (Schläpfer 2009). In fact a recent study (Jackson 2012) found that in 2008 Australia ranked 16th out of 19 G20 countries in its ability to deal with a low carbon emissions world. It was the only G20 country whose ability to cope with a low carbon emissions world decreased since 1995. Reasons for Australia's low score include the small renewable energy contribution and the country's high per capita emissions. However, the recent introduction of the carbon pricing mechanism is likely to have improved this poor ranking.

Historically, electricity prices have been low in Australia and they are still low compared to other OECD countries (Bureau of Resources and Energy Economics 2013). This is one of the main reasons for the absence of CSP plants as they currently have higher levelised costs of electricity (LCOE) than wind or biomass. However, since 2006 business and particularly households have experienced above average electricity price rises (see Figure 5), with the main cost components being distribution (42%), wholesale (24%), retail (13%), transmission (8%), and the large-scale renewable energy target (7%) (Australian Energy Market Commission 2011). From 2013 to 2016 household electricity prices are expected to stabilise in most states except for Queensland and the Northern Territory where further increases of 8.6% and 6.9% are expected (Australian Energy Market Commission 2013). Despite the significant retail electricity price rises, wholesale electricity prices have not increased sufficiently, currently around AU$ 50/MWh (RepuTex 2013), to make CSP and other renewable plants viable. This is the case even with the inclusion of the current AU$ 30/MWh price premium for renewable energy certificates (RECs) (RepuTex, 2013) and a carbon emission price of AU$24.15/t CO2 in 2013–14 (Australian Government 2011). The proposed repeal of the carbon pricing mechanism by the recently elected Liberal government (The Parliament of the Commonwealth of Australia 2013b) is expected to lower average wholesale electricity prices to AU$ 31/MWh in 2014 (RepuTex, 2013) which would slow renewable energy growth by reducing the financial incentive and adding market uncertainty around the development of new projects.

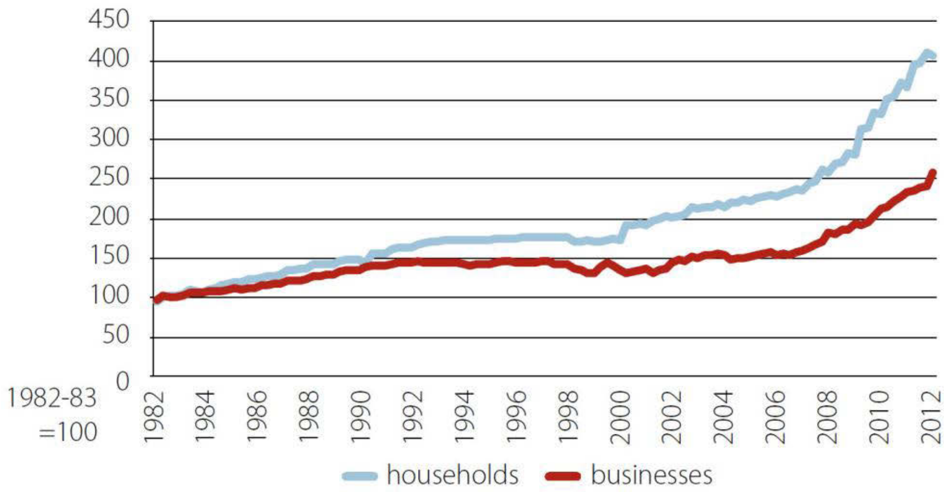

Figure 5: Electricity price indices for households and businesses, Australia (Bureau of Resources and Energy Economics 2013)

2.1.2 Transition to a low carbon future[1]

According to a recent Australian survey 80% of the interviewees accept that climate change is happening and that human activity significantly contributes to it (Leviston et al. 2014). Despite the high acceptance climate change does not rank high as an important social or environmental concern (Leviston et al. 2014), since issues such as employment, health, water shortages and pollution are considered more important and immediate. Globally, climate change is expected to increasingly impact on the social world including the displacement of millions of people, human and food security, violent conflict and human

[1] The current political and legislative environment in relation to climate change and emissions reduction is a very dynamic area in Australia and the information provided are valid until the submission date of this thesis, the 9th April 2014.

health (Barnett & Adger 2007; Nordås & Gleditsch 2007; Reuveny 2007). It will be increasingly difficult for Australia to isolate itself from these developments.

The Australian government's commitment to climate change mirrors the public acceptance and its priority ranking shown in the aforementioned survey. The current government policy acknowledges climate change is occurring but their actual commitments to lower greenhouse gas emissions are weaker than that of many comparable countries, such as the USA and the UK (Climate Change Authority 2013). Australia is committed to reducing its greenhouse gas emissions by 5% by 2020, compared to the year 2000, and the previous government was prepared, and had bipartisan support, to increase this target to 25% if both developed and developing nations in the international community agreed on more ambitious goals (see Figure 6) (Department of Climate Change and Energy Efficiency 2012). The policy of the recently elected government is not yet known and announcements are expected in the lead-up to the 2015 UN climate conference in Paris (Hunt 2014).

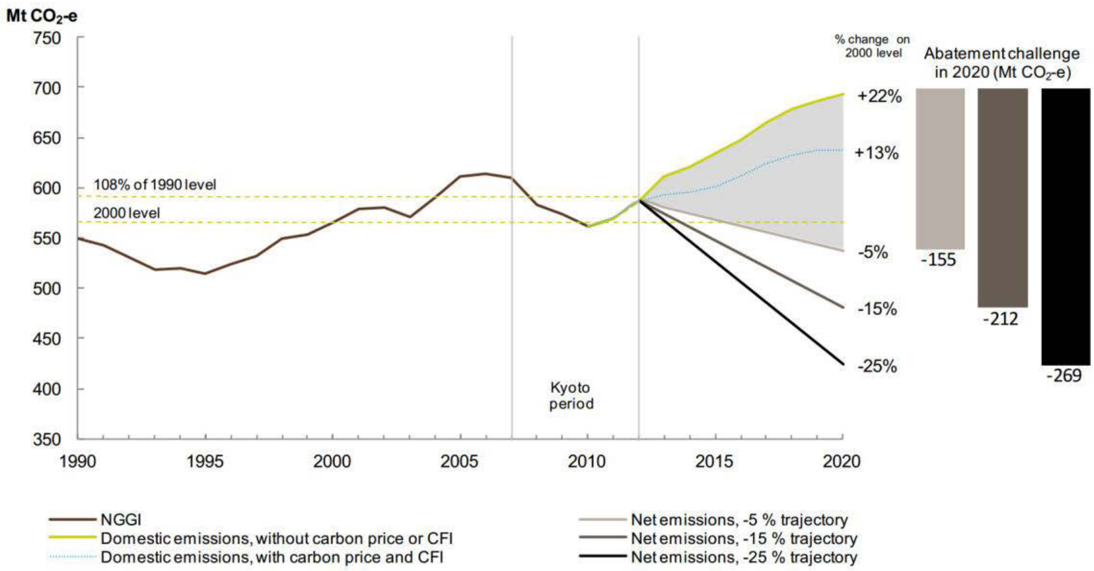

Figure 6: Australia's emissions trends, 1990 to 2020 (Department of Climate Change and Energy Efficiency 2012)

Currently, the two main mechanisms to attain the 2020 greenhouse gas emissions reduction target are the Renewable Energy Target (RET) of 45 TWh by 2020 (Climate Change Authority 2012) and the carbon pricing mechanism (Australian Government 2011). The RET consists of 41 TWh electricity from large-scale plants and 4 TWh from small scale renewable energy installations (Climate Change Authority 2012). The policy is currently under review (Hunt & Macfarlane 2014) and this might result in a lower 2020 target which is adding to investment uncertainty. Australia's current carbon pricing mechanism has a fixed price period without a pollution cap until 1st July 2015 when it is to transform to a flexible market price with a pollution cap on annual greenhouse gas emissions thereafter

(Australian Government 2011). However, the recently elected Liberal government plans to replace this policy with their "direct action" policy. The Emissions Reduction Fund is a key part of the policy and consists of a reverse auction process to buy back the lowest-cost abatement options (Commonwealth of Australia 2013). The Australian Renewable Energy Agency and the Clean Energy Finance Corporation are two entities providing funding for renewable energy projects (Australian Renewable Energy Agency 2014; Clean Energy Finance Corporation 2014) but the latter is slated to be shut down by the recently elected government (The Parliament of the Commonwealth of Australia 2013a).

The current policy uncertainties around the proposed repeal of the carbon pricing mechanism and the simultaneous commissioning of several liquefied natural gas export facilities, linking Australia to world natural gas prices, could see annual coal generation in 2014 return to more than 80% of electricity generation (RepuTex 2013). Average natural gas prices are expected to rise from a current average of AU$ 6/GJ to AU$ 9/GJ in 2020. Electricity generation from natural gas without a carbon pricing mechanism could therefore halve over that period (RepuTex 2013). A first sign of this trend actually occurring is the mothballing of a large natural gas fired power plant and the replacement of its capacity through the re-commissioning of an old coal fired unit (Hepworth 2014). However, a recent construction forecast from 2014–18 for utilities in Australia (Macromonitor 2013) predicts ongoing deployment of natural gas (3,100 MWe) and wind capacity (3,838 MWe) but no new coal capacity. The analysis upon which this forecast is based includes off-grid infrastructure projects which rely heavily on natural gas for power generation and process heat. The repeal of the carbon pricing mechanism would slow large-scale wind generation growth from an expected 12% annual electricity contribution to 7.5% in 2020 with the generation difference provided by coal (RepuTex 2013). Other forms of renewable energy deployment are expected to grow by 308 MWe from 2014 to 2018[2] (Macromonitor 2013). This growth is significantly slower than the growth in wind generation. Figure 7 shows a high annual investment of around AU$ 2.3b in renewable energy capacity from 2013 to 2015 but continuously falling investment for the period through to 2018. With the committed 2013–15 investment new renewable capacity is expected to peak at 1,550 MW in 2016 and fall sharply to below 600 MWe annually in 2017 and 2018.

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[2] The Macromonitor report only investigates utility scale plants and does not include residential and commercial PV installations.

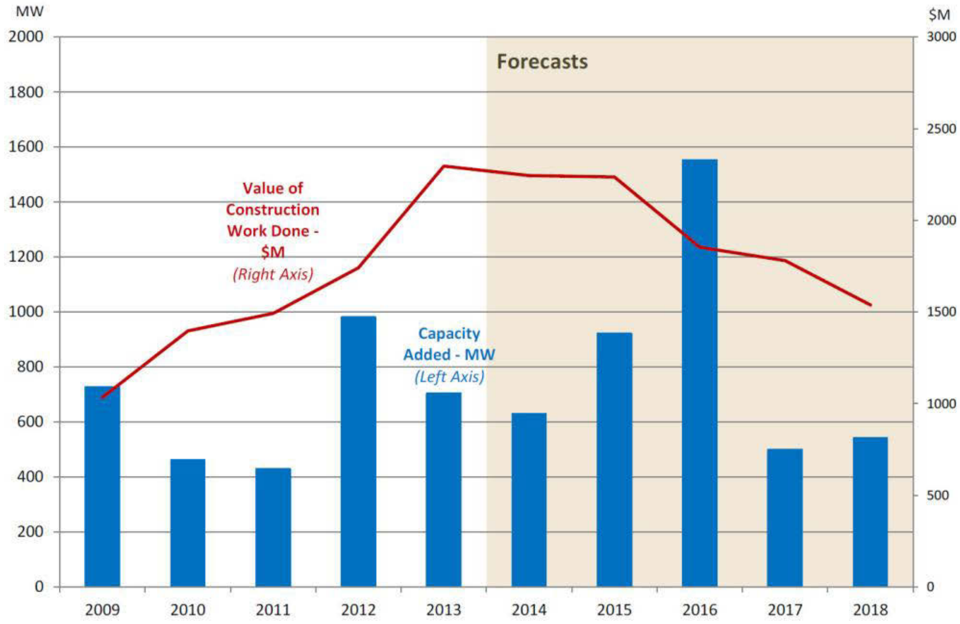

Figure 7: Forecast renewable energy investment – value of construction and capacity added (Macromonitor 2013)

Renewable energy deployment until 2020 will depend to a large extent on policy changes in 2014 and 2015. It is possible that there will be significant growth due to the carbon pricing mechanism in combination with the RET and rising natural gas prices making renewables a more attractive option. Or there may be marginal growth due to the repeal of the carbon pricing mechanism and the weakening of the RET. Hence investment uncertainties are high at this point in time.

The strategic transition to a low carbon future is supported by the previous Australian Government through their 80% carbon emission reduction target by 2050 compared to 2000 emission levels (Department of Climate Change and Energy Efficiency 2012). The position of the recently elected Liberal government is not yet known. However, apart from an analysis of the possible Australian energy mix by 2049–50 (Syed 2012) a detailed policy proposal for the transition process beyond 2020 is missing. Several institutions have proposed significantly different pathways to reduce greenhouse gas emission by 2050. These pathways include: the use of 100% renewable electricity (Elliston, MacGill & Diesendorf 2013; Wright et al. 2011); the rapid expansion of natural gas (Australian Petroleum Production and Exploration Association 2010); and the implementation of low emissions coal technologies (Australian Coal Assocation 2014).

According to Syed (2012) a mix of all of the above will occur by 2050 with natural gas and coal providing 49% of annual generation and renewable energy sources providing 51% (see Figure 8). The use of brown coal will decrease significantly to 5 TWh in 2034–35. Brown coal is not part of the predicted 2049–50 electricity mix, and neither is oil. The share of natural gas is expected to increase over the same period with the strongest growth occurring from 2034–35 to 2049–50. Wind and solar are each expected to surpass hydro as sources of renewable electricity by 2034–35 but their growth patterns are different. While wind is expected to grow strongly through to 2034–35 and only marginally from there to 2049–50 solar is expected to grow more slowly until 2034–35 and increase its market share more strongly from there to 2049–50. It is also expected that geothermal will grow continuously to 2049–50 but will remain below 10% of market share while bioenergy will provide only a small amount of renewable electricity.

While the Syed (2012) report has a robust scientific method, some of the assumptions, such as an increase in electricity demand from 254.7 TWh in 2011–12 to 377 TWh in 2049-50, make its results prone to error. The basis for the expected electricity increase includes continuous population and economic growth but even though both have occurred from 2010 to 2013, electricity demand decreased as shown in Figure 2 on page 6. Also the actual cost of fossil fuels, renewable energy generation and energy efficiency technologies might differ to the assumptions, and this would also affect the overall result. Predicting technology costs, market changes and technology implementation three decades ahead is a difficult task with various unavoidable uncertainties and while the details of the energy transition to 2050 are uncertain it is clear that a transition is necessary and this will require substantial changes to the current electricity market. Financial incentives will be needed in the near future to implement renewable and low carbon intensity energy technologies, and further research will be needed to develop the power technologies for the future.

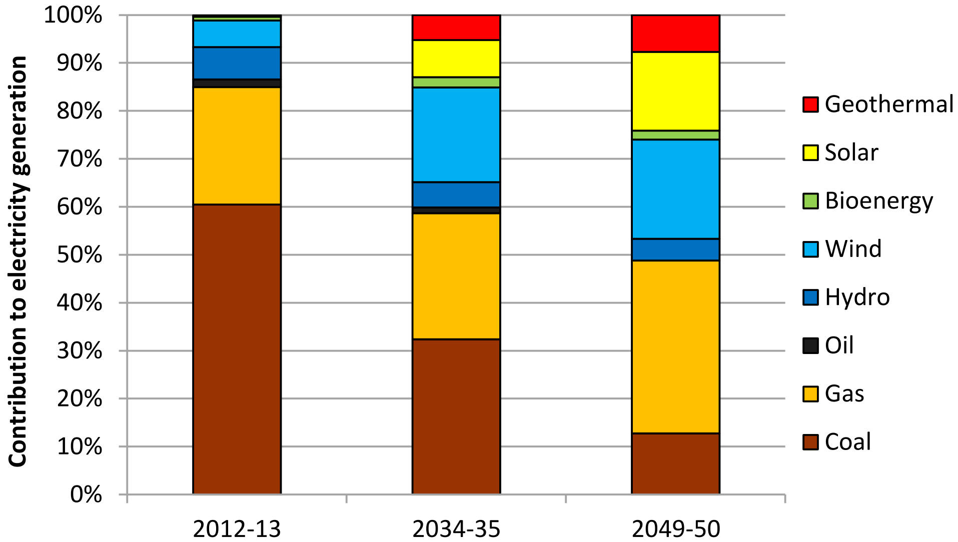

Figure 8: Share of electricity generation by energy type, prepared with data from Syed (2012)

2.2 Concentrating solar power plants

Over the last century CSP has developed from theoretical concepts and first test units to a utility scale power generation option. This chapter outlines this development to date and future growth trajectories worldwide. It also provides as an update on CSP in Australia.

2.2.1 History and technology development

The development of line and point focusing systems started in the 19th century with the work of pioneers including Augustin Mouchot's research on dishes, John Ericsson's research on parabolic troughs and William Adams's research on solar towers (Ragheb 2011). However, the first commercial CSP plant, Solar Engine One shown in Figure 9, was not installed until 1912. It was developed in Egypt to pump irrigation water from the river Nile to a nearby farming community (New York Times 1916; Stinnesbeck 1914). The plant used five parabolic troughs with direct steam generation to operate a 100 horsepower pump and it used pressurised hot water storage to continue operation into the night (New York Times 1916; Stinnesbeck 1914). This CSP plant could compete with coal-fired generation in regions where coal prices exceeded 10 German Marks per tonne and it was easier to operate than a coal boiler (Stinnesbeck 1914). The British and German governments planned further units for their colonies (New York Times 1916) but World War I led to the dismantling of the plant and the abandonment of plans for further installations. Low prices and good availability of fossil fuel after World War I stopped CSP developments for the next several decades.

Figure 9: Al Meadi pumping station using the five parabolic troughs with direct steam generation (Stinnesbeck 1914)

In the 1970s the first commercial CSP plants were designed for electricity generation as a reaction to the oil crises and the subsequent search for energy alternatives. The first of nine Solar Energy Generation Systems (SEGS), using the parabolic trough technology, was a

14 MWe plant commissioned in 1984. Plant sizes rose incrementally to 80 MWe with all nine units having a combined capacity of 354 MWe in 1990 (Skumanich 2011). However, history repeated itself and decreasing oil prices in the 1990s stopped the construction of further commercial plants until 2006 when Spain introduced Royal Decree 436/2004 (Ministerio de Economia 2004) which offered plant operators a fixed feed-in tariff price or a feed-in premium on top of the wholesale electricity price. In addition to the established parabolic trough technology with thermal oil a variety of new technologies emerged on the commercial CSP market. These included solar tower and Fresnel systems, working fluids such as molten salts, and direct steam generation.

Due to the long operational experience with SEGS, in 2012 parabolic trough systems using thermal oil as the primary working fluid had a global market share of 94% of deployed capacity (IRENA 2012) and they remain the dominant CSP technology. Many commercial reference plants exist with and without thermal energy storage (TES) (IRENA 2012) and recently plants have reached capacities of 280 MWe (Abengoa Solar 2013b). To overcome the efficiency limits dictated by accelerated thermal oil degradation at temperatures above 400 °C, some suppliers offer parabolic trough systems with molten salt and direct steam generation. The first small commercial reference plants using this technology are already in operation. Examples include the 5 MWe Priolo Gargallo plant with molten salt in Italy (Falchetta et al. 2009) and the 5 MWe Kanchanaburi plant with direct steam generation in Thailand (Krüger et al. 2012).

Currently, solar tower systems are not considered to be as mature as conventional parabolic trough plants but since the early 1980s several experimental systems have been field tested in Russia, Italy, Spain, Japan, France, and the United States (Meinecke, Bohn & Becker 1995). These include the 10 MWe Solar One and Two in the USA and the 5 MWe SPP-5 in Russia. The PS10 solar tower in Spain began operating in 2006. It is able to generate 10 MWe (net), and it was the first commercial tower plant to commence operation (Solúcar 2006). Further commercial projects with steam and molten salt as the primary working fluid commenced operation or are under construction in Spain, the USA and South Africa. They include the 5 MWe Sun Sierra plant (eSolar Inc. 2013), the 20 MWe PS20 plant (Abengoa Solar 2014b), the 20 MWe Gemasolar plant (García & Roberto Calvo 2012), 50 MWe Khi Solar One (Abengoa Solar 2013a), the 110 MWe Crescent Dunes plant (SolarReserve LLC 2012), and the 392 MWe Ivanpah plant (BrightSource Energy Inc. 2013) shown in Figure 10. Not all plants have TES but many do, with full-load capacities ranging from 2 to 15 h. A new 110 MWe plant with 17.5 h TES is scheduled to commence construction later this year in Chile (Abengoa Solar 2014a).

Figure 10: One of three solar tower systems of the 392 MWe Ivanpah power station, USA[3]

In addition to Rankine cycles, solar towers can be combined with Brayton cycles to raise cycle efficiency and reduce cost. Experimental systems exist for high-temperature air applications, such as the 230 kilowatt (kWe) SOLGATE project in Spain (ORMAT et al. 2005) and the recently commissioned 4.6 MWe Solugas project in Spain (Quero et al. 2013). However, high-temperature air is also used to operate conventional Rankine cycle systems (e.g. 1.5 MWe Solair/HiTRec project in Germany) (Koll et al. 2009). Also under development are experimental solar towers for hydrogen production through steam reforming of natural gas with the largest prototype being a 300 kWe installation in Australia (Stein et al. 2009). Similarly, a 1 MWth solar tower prototype to convert solid biomass into synthesis gas was built in 2010 and is currently being tested in the USA (Service 2009). As seen from the aforementioned examples solar tower technology is versatile, and with the recent commissioning of several utility scale plants, particularly Ivanpah and Crescent Dunes, they can demonstrate their technical and commercial expectations. If these plants are successful the technology is very likely to gain a significant CSP market share.

Like solar tower plants, Fresnel is a CSP technology that is currently proving its technical benefits and commercial viability. Some commercial plants are already in operation, such as the 5 MWe Kimberlina in the USA (NREL 2014b) and 30 MWe Puerto Errado in Spain (Novatec Solar GmbH 2012c). In addition, larger units are under construction. These include the 44 MWe Kogan Creek Solar Boost hybrid in Australia (CS Energy 2011) and the 2x 125 MWe Reliance project in India (AREVA Solar 2012a). The market share of Fresnel plants is

[3] www.brightsourceenergy.com/image-downloads, accessed 04 April 2014

even smaller than that of solar towers (IRENA 2012) and the plants currently in operation or under construction are crucial for establishing the technology as a credible CSP alternative. Currently, Fresnel plants are only offered commercially with direct steam generation but recently research has started into the use of molten salts to simplify the integration of TES (AREVA Solar 2014; Novatec Solar GmbH 2013).

The simplicity of the Fresnel collectors raises expectations for significant cost reductions but the technology has the disadvantage that TES is not yet commercially available. However, this might change in the near future with the successful testing of molten salts and ongoing TES developments involving phase change materials for direct steam systems (Bahl et al. 2011; Kuravi et al. 2013; Laing et al. 2012; Nithyanandam, Pitchumani & Mathur 2014; Yin, Ding & Yang 2014).

Predominantly, parabolic dishes are used in conjunction with Stirling engines, for example at the 50 kWe plant in Saudi Arabia (Noyes 1990), and concentrating PV systems, for example at a 1.5 MWe plant in Australia (Silex Systems Ltd 2013). However, some dish systems are designed for Rankine cycle operation and the 4.9 MWe Solar Plant 1, commissioned in 1984 in the US, was the largest plant in the world using a primary molten salt and secondary superheated steam cycle (Stolpe 1986). Technical problems saw the unit converted to a solar-diesel hybrid plant and the construction of further units was halted (Larson & West 1996). A smaller 25 kWe plant commenced operation in Australia in 1983 (Kaneff 1991) but was dismantled in 1994 with the reflector surface further used for concentrating PV testing (Gordon 2001). Despite having the highest concentration ratio and the potential for excellent conversion efficiencies (Lovegrove & Luzzi 2002) dish systems have not played a relevant role in recent commercial CSP projects. The reasons for their very limited uptake are likely to be the small number of reference plants worldwide, concerns about plant complexity through extensive hot and cold working fluid piping, the lack of established construction companies offering such plants with all standard guarantees, and high finance costs associated with technologies which have not been widely tested. At the Australian National University a 500 m^2 big dish designed to operate a Rankine cycle is being tested and commercialised (Lovegrove, Burgess & Pye 2011) but so far no complete demonstration plant has been built. A state grant for a commercial project was awarded but later withdrawn (Edwards 2013; Regional Development Australia 2011).

The new CSP technologies emerging in commercial projects combined with innovative TES systems have the potential to lower LCOE significantly but require ongoing deployment to convince financiers to invest in them at levels comparable to current levels of investment in conventional parabolic trough plants. The recent revival and technological diversification of commercial CSP plants has enabled the CSP industry to increase its cumulative capacity from 354 MWe in 1990 to 4 GWe in 2013 (International Energy Agency 2013). The capacity of individual plants has also risen, with the largest plant to date being the 280 MWe Solana (Abengoa Solar 2013b) and the 390 MWe Ivanpah plants (BrightSource Energy Inc. 2013) in the US. Both of these plants were commissioned recently.

2.2.2 Outlook

In its recent renewable energy projections the International Energy Agency (2013) estimates an increase in cumulative CSP deployment from 4 GWe in 2013 to 12 GWe in 2018. While tripling the installed capacity is a good outlook for the industry, it is worth putting this in perspective with PV installations, which are expected to grow by a slightly smaller factor of 2.4 but from a 2013 basis of 128 GWe (see Figure 11). Wind generation, with a cumulative deployment of 321 GWe in 2013, is even stronger. It is apparent that in the solar market PV has a much stronger share than CSP but it is also apparent that the expected 2018 capacity factor for CSP of 32% (34 TWh generation with 12 GW deployed capacity) is much higher than for PV of 14% (368 TWh with 308 GWe). This is an expected increase from an average CSP capacity factor of 26% in 2013 (9 TWh with 4 GW), which indicates that the availability of mature TES is an important distinction to PV and it will play an increasingly important role.

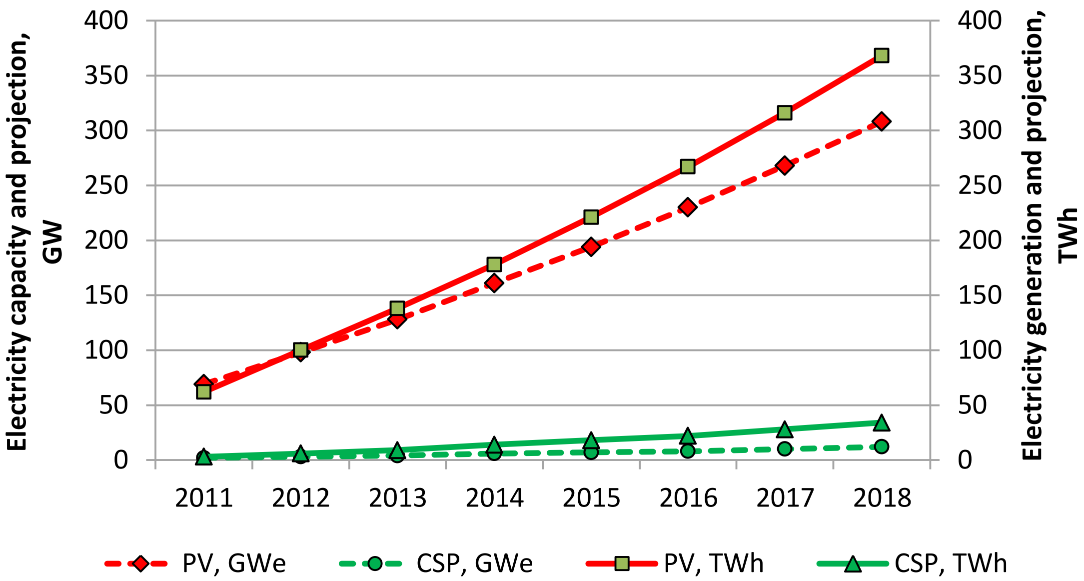

Figure 11: Annual electricity capacities and generation for CSP and PV from 2011-18 (International Energy Agency 2013)

In recent times the significant cost reductions of PV systems have put pressure on CSP and the decision to switch the first 500 MWe phase Blythe parabolic trough project in the USA to PV is the most prominent example of the competition with PV so far (Beetz 2012). Even larger PV projects with capacities ranging from 700 to 4,000 MWe are being developed (Sempra U.S. Gas & Power 2012; Willis 2014), and in 2013 83% of new solar projects in the USA were PV (GTM Research & Solar Energy Industries Association 2013). This shows that TES is not yet valued sufficiently because its cost are still high and because fossil powered assets, particularly natural gas, can quickly offset PV shortfalls. However, when considering higher penetration renewable energy scenarios CSP is complementary to PV as intermittent renewable sources require dispatchable renewable sources to ensure stable grid operation (Denholm & Mehos 2011; Elliston, Diesendorf & MacGill 2012).

In order to remain competitive, the CSP industry must not only reduce the solar field cost but also the TES cost. A variety of research and development (R&D) activities aim to improve TES using sensible heat, latent heat and thermochemical concepts (Kuravi et al. 2013). Sensible heat storage systems raise the temperature of a medium, such as molten salt, and the amount of energy stored depends strongly on the medium's heat capacity. The storage medium does not change its phase and it is currently the dominant TES technology. Latent heat storage is a nearly isothermal process. It has the potential to store significantly more energy than sensible storage systems of the same temperature range because the storage capacity of latent heat systems depends not only on the storage medium's specific heat but also on the enthalpy of phase change. Thermochemical storage systems use the heat from the solar field to drive reversible chemical reactions. Currently they are the least mature storage technology but they have the potetnial to store more energy than the two aforementioned technologies. It is expected that through R&D and technology deployment TES costs will decrease from AU$ 90/MWth in 2011 to AU$ 22/MWth in 2020 (Hinkley et al. 2011). Continuous CSP deployment could lower the 2011 LCOE range of US$ 160-270/MWh to US$ 100-140/MWh by 2020 for parabolic trough systems and to US$ 80-160/MWh for solar tower systems (IRENA 2012). Obviously, these are high-level predictions, which depend on the actual CSP deployment and the technological progress made by 2020, and more specifically on the solar resource (see direct normal irradiance (DNI) impact in Figure 12), the plant location, local labour costs, CSP technology, finance conditions, and plant and TES capacity.

In recent years CSP deployment has been driven by government incentives, such as feed-in tariffs in Spain (Ministerio de Economia 2004) and loan guarantees in the USA (U.S. Department of Energy 2013a). New technologies require support to enter a market but this comes with the risk that costs will not decrease as quickly as possible anticipated or that governments will shift focus and support mechanisms will disappear. The latter happened in 2012 in Spain when feed-in tariffs for CSP were retrospectively reduced by Royal Decree 1/2012 (Jeafatura del Estado 2012) with the result that the fastest growing CSP market worldwide disappeared almost overnight. Similarly, in the USA loan guarantees enabled the construction of the largest CSP plants worldwide but with these plants being completed or moving closer to completion no new plants are under construction. Other markets exist to compensate for these shortfalls and ensure continuous CSP growth. Examples include the Middle East and North Africa region target of 37.5 GWe by 2032 (Bryden, Riahi & Zissler 2013), India's 20 GWe target by 2022 (Ministry of New and Renewable Energy 2011), and China's 3 GWe target by 2020 (Lluna 2011). However these targets also rely on government support mechanisms which can disappear quickly. In summary future CSP deployment is not easy to predict as unforeseen events can occur and unfortunately the ambitious 2020 target of 30 GWe predicted by AT Kearney Consulting in 2010 is unlikely to be realised.

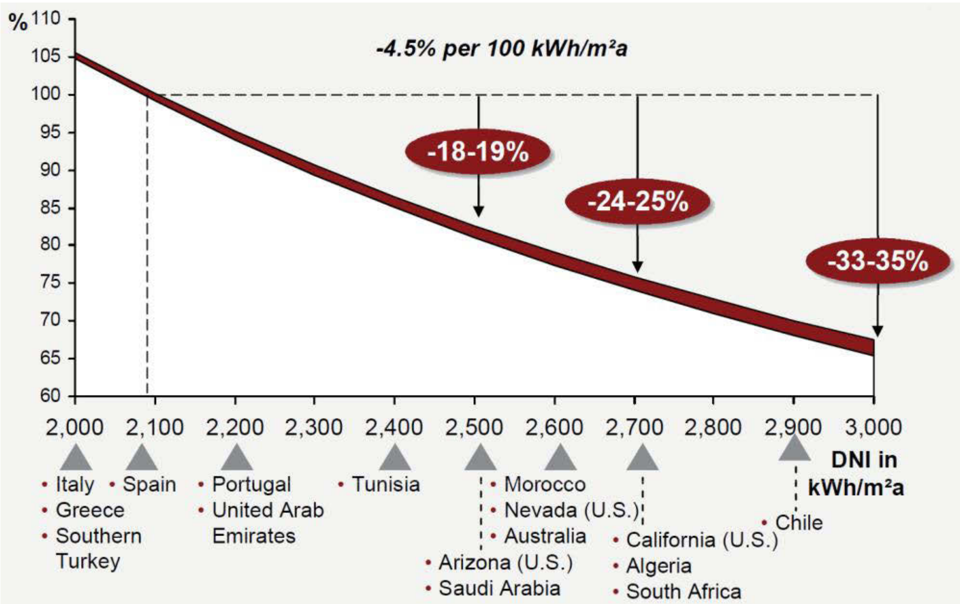

Figure 12: Tariff and levelised cost of energy development above DNI level; Percentage compared to reference plant in Spain with a DNI of 2,084 kWh/m²/a at 100 per cent (AT Kearney & ESTELA 2010)

In addition to learning from deployment, R&D programs can reduce LCOE and currently various projects worldwide aim to do this. Two significant projects are the Sunshot Initiative from the USA with an LCOE target of US$ 60/MWh (SunShot Initiative 2012) and the Australian Solar Thermal Research Initiative (ASTRI) which aims to reduce LCOE to AU$ 120/MWh (CSIRO 2013) by 2020. Both investigate novel concepts, including super-critical CO_2 cycles, to significantly increase cycle efficiency. While the ASTRI goal is ambitious it is within the range of other studies (IRENA 2012). However, the Sunshot goal seems very challenging and a recent assessment concluded that the probability of achieving it is very low. However, a 50% chance exists to reach US$ 120/MWh (Ho, Mehos & Wagner 2014).

Finance is particularly relevant for CSP projects and developers prefer large projects to gain economy-of-scale benefits. However, this has the consequence that project budgets can easily reach hundreds of millions or even a billion dollars. For example the 50 MWe Andasol plant in Spain had a budget of € 300m (Solar Millennium AG 2006), 280 MWe Solana plant has a budget of US$ 2b (NREL 2014d), and the 392 MWe Ivanpah plant had a budget of US$ 2.2b (NREL 2014a). The consequences of combining large project budgets with less mature technologies are high finance risk premiums, and this is one reason for the dominant market share of parabolic trough plants despite their lower efficiency compared to solar tower and Fresnel systems (see Figure 13). The recent commissioning of new solar tower plants and the growing confidence in the technology has meant that in 2013 there were more plans for tower projects than for parabolic trough projects. However, planned parabolic trough plants are still very significant and the technology is likely to retain a dominant role in regards to deployed capacity for years to come (see Figure 13). Fresnel, and particularly dish systems, will have to mature significantly to reach a higher market penetration in the future.

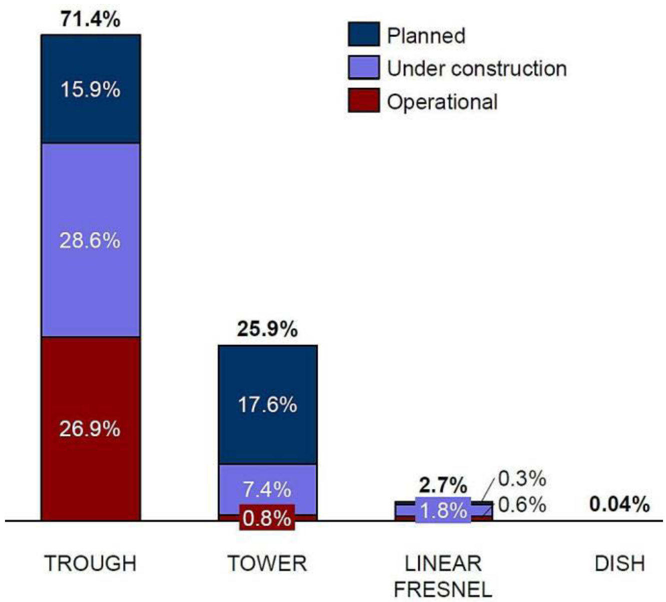

Figure 13: CSP project pipeline by technology in per cent of total CSP projects as per 1st March 2013 (SBC Energy Institute 2013)

2.2.3 Australian market

Australia has one of the best solar resources in the world (see Figure 14), and according to a recent CSP study for Australia (Lovegrove et al. 2012) the potential for off-grid CSP (plants <10 MWe) is 100 MWe, for medium-scale CSP (10-20 MWe plants) it is 720 MWe, and for utility-scale CSP connected to the current grid (>20 MWe plants) it is for 3-4 GWe. However, the current situation is very different as Australia has been a very slow adopter of CSP with a variety of reports investigating ideal sites and costs (Cameron & Crompton 2008; Clifton & Boruff 2010; Dawson & Schlyter 2012; Feeney et al. 2010; Lovegrove et al. 2012; Parsons Brinckerhoff Australia Pty Ltd 2010; Rutovitz et al. 2013; Wright et al. 2011) but no commercial stand-alone plants under construction or in operation. The only two commercial developments are two Fresnel systems attached to coal fired generators. These are the operational 18.3 MWth system at the 2 GWe Liddell power station, comprising a 9 MWth field build in 2008 and a 9.3 WMth field built in 2012 (AREVA Solar 2012b; CSP World 2014; Novatec Solar GmbH 2012a), and the 44 MWe equivalent system under construction at the 750 MWe Kogan Creek power station (CS Energy 2011).

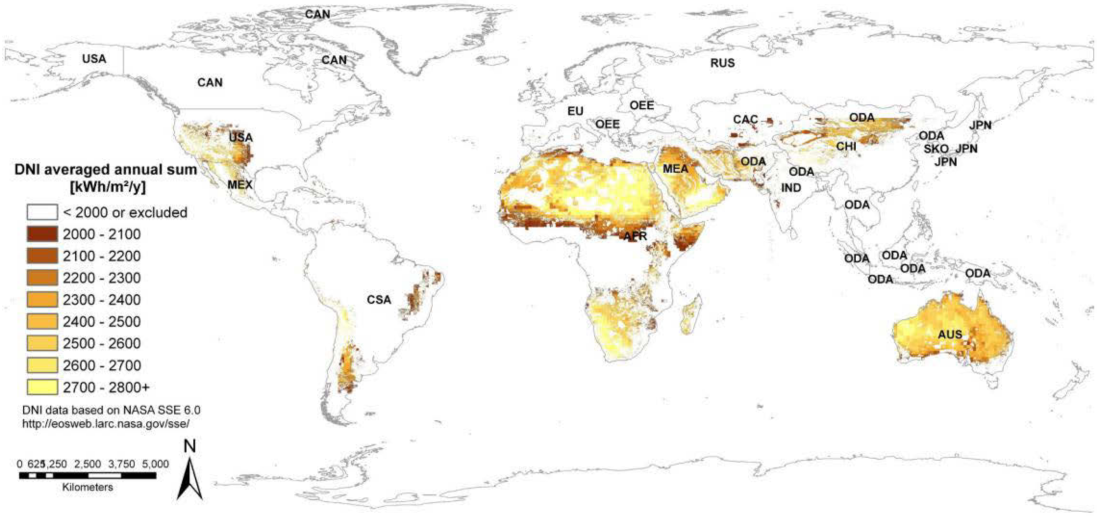

Figure 14: Direct normal irradiation for potential global CSP sites (Trieb et al. 2009)

Attempts were made by former state and federal governments to build commercial CSP plants through the allocation of AU$ 464m for a 250 MWe Fresnel plant in Queensland (AREVA Solar 2011) and AU$ 60m for a 40 MWe SolarOasis big dish plant in South Australia (Regional Development Australia 2011). However, neither could not secure the remaining finance and were subsequently withdrawn (Edwards 2013; Kelly 2012). The only stand-alone CSP plant to operate in Australia for an extended period (between 1983 and 1994) was the 25 kWe White Cliffs project which used dishes to operate a steam engine (Gordon 2001). A larger 100 kWe system at Meekathara in Western Australia commenced operation in 1982, using small troughs to operate an organic Rankine cycle, but was only operational for a short period (Hellweg 1983). In 2011 a 3 MWe multi-tower test plant was set up (Lloyd Energy Systems 2011) and another 1.2 MWe multi-tower plant is currently under construction (ABC 2013; CSP World 2013).

Options to increase the financial viability of CSP in the current electricity market exist and include placing plants in grid-constrained locations, thereby deferring or even offsetting investment in transmission infrastructure (Rutovitz et al. 2013) and off-grid applications where they compete with costly diesel or natural gas fuelled plants.

Low wholesale electricity prices, fossil fuel subsidies, the lack of a stable support mechanisms, and the absence of full externality costing for fossil generators mentioned in Section 2.1.1 are key reasons for the absence of commercial CSP plants in Australia. Currently, only hybrid plants seem viable due to lower costs, relative to CSP-only plants, achieved through the joint use of plant equipment, such as steam turbines and condensers. The AU$ 104.7m for the 44 MWe equivalent CSP retrofit to the Kogan Creek power station (CS Energy 2011) represents a significantly lower specific investment (AU$ 2.4m/MWe) than the AU$ 200m for the 53 MWe PV plant (AU$ 3.8m/MWe) about to be constructed in Broken Hill (Boisvert 2013; Hobson & Winsbury 2013). Therefore CSP hybrids seem to offer a promising transition technology to allow CSP to enter the Australian market, build local learning experience and increase investment confidence. Further to the two current CSP retrofits plants, new hybrid projects are currently being investigated with natural gas, such as 30 MWe Collinsville proposal (Australian Renewable Energy Agency 2013a), and with biomass/waste feedstocks such as the 35.5 MWe Swanbank proposal (Ipswich City Council 2012; Peterseim et al. 2012b). Also a recent study on the retrofit of CSP to existing fossil fuel plants identified nine opportunities with natural gas and seven with coal (Meehan 2013).

To lower the future cost of CSP the Australian government is investing in R&D programs to progress cutting edge technologies. Projects include the recent AU$ 87.3m ASTRI development (CSIRO 2013), test facilities for the big dish in Canberra (Lovegrove, Burgess & Pye 2011), and solar tower test facilities in Newcastle (CSIRO 2012).

2.3 Non-conventional fuels for power generation

In this research the term 'non-conventional fuels' refers to waste feedstocks, such as wood waste and refuse-derived fuels, and solid biomass feedstocks, such as wood, straw and bagasse. These are used widely worldwide but despite their benefits, such as renewable energy generation and landfill diversion, they are also controversial in regards to debates about food versus fuel and material versus energy recovery.

A variety of thermochemical, physiochemical and biochemical technologies are available to convert biomass and waste feedstocks to thermal energy (see Figure 15). However, the focus of this research is the hybridisation of solid materials with CSP in Rankine cycle systems and the literature review is therefore limited to direct combustion, gasification, plasma, and pyrolysis treatment options.

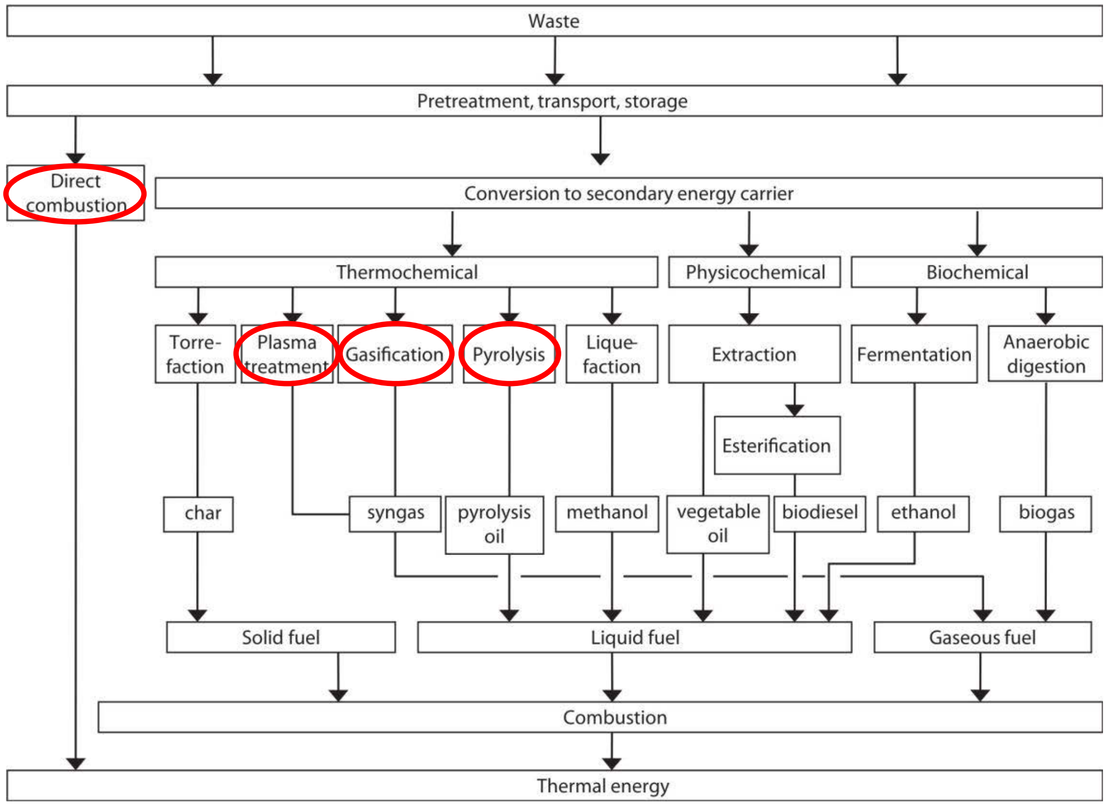

Figure 15: Energy from waste conversion technologies (Kaltschmitt 1998)

2.3.1 Energy from waste

Permanent open fires burning waste were reported in Jerusalem as early as 1,000 B.C. but the first industrial Energy from Waste (EfW) facility was built in London in 1870 to guarantee the destruction of germs in municipal waste streams (Vehlow 2004). Other cities in Europe followed by building plants able to provide electricity and/or heat (e.g. EfW plants in Hamburg in 1896 – shown in Figure 16a – and Copenhagen in 1903). It is worth mentioning that these facilities were accompanied by the construction of recycling plants for paper, textiles, leather glass and metal (Vehlow 2004).

Since the commissioning of these first plants EfW technologies have improved significantly in regards to cycle efficiency, from 15–21% in the 1980s to over 30% in recent units (Gohlke 2008), and emissions (e.g. dioxin and furan emissions fell by 99% between 1990 and 2005 (Stevenson 2007). These improvements were possible through a variety of technologies including higher steam parameters, steam reheating, optimised combustion, minimised parasitic losses, and high efficiency baghouse filters and flue gas scrubbing.

Today almost 2,200 commercial EfW plants operate worldwide (ecoprog 2013) many of them in the middle of densely populated cities, such as Paris, London, Berlin, and Tokyo (as shown in Figure 16b), where waste materials are created and electricity and process heat is needed. In 2006 EfW plants produced 46 TWh of electricity and an equal amount of process heat worldwide (Themelis 2006) and by 2017 another 180 plants are expected to be operational (ecoprog 2013).

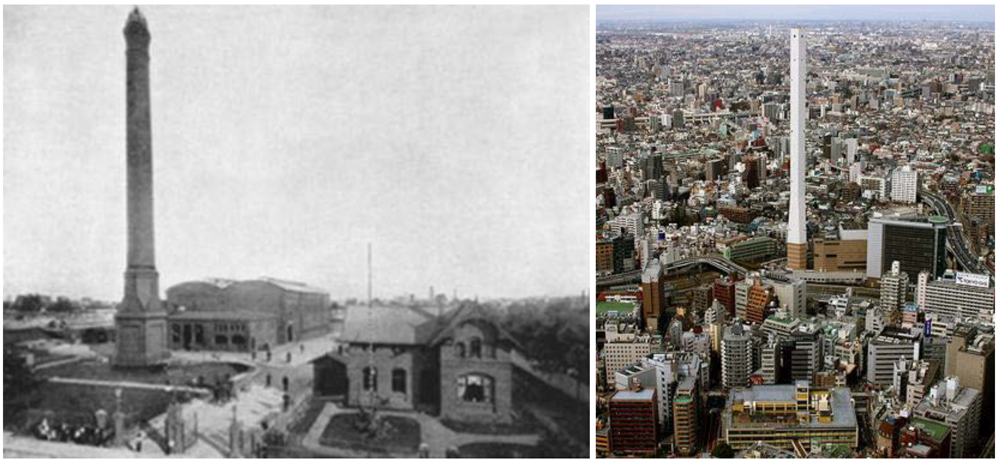

Figure 16: a: Waste incineration plant Bullerdeich in Hamburg in 1896 (Vehlow 2004) and b: modern Energy from Waste plant in Tokyo, Japan (right)[4]

Prior to using waste materials for energy recovery, higher priority has to be given to waste prevention, reuse and recycling. Despite debates about the competition of waste recycling with EfW, Figure 17 shows that typically countries with EfW facilities have higher recycling rates than countries without (European Environment Agency 2007). This supports the finding made by German Federal Environment Environment Agency that:

> *waste incineration does not have a negative impact on waste prevention. Its primary task is the safe and proper disposal of wastes not avoided and not recycled. Waste incineration thus delivers the disposal security which remains necessary in a*

[4] Image courtesy Logan Mirto

recycling economy based on material and resource efficiency (German Federal Environment Agency 2008, p. 5).

Countries with recycling facilites have the ability to recover recyclable materials and use the remaining material streams for energy recovery rather than disposal in landfills. For example in 2005 Germany introduced a landfill ban on waste materials with an organic content of more than 3% and since then the majority of municipal solid waste has been recycled, non-recyclable materials have been used in EfW plants providing electricity and heat, and less than 1% of municipal solid waste has gone to landfill (European Environmental Agency 2009). In the future new recycling technologies are likely to enable higher recycling rates and reduce the amount of material available for EfW plants, but for the foreseeable future different EfW technologies, including landfill gas and aerobic and anaerobic digestion systems, will continue to play an important role in global waste management strategies.

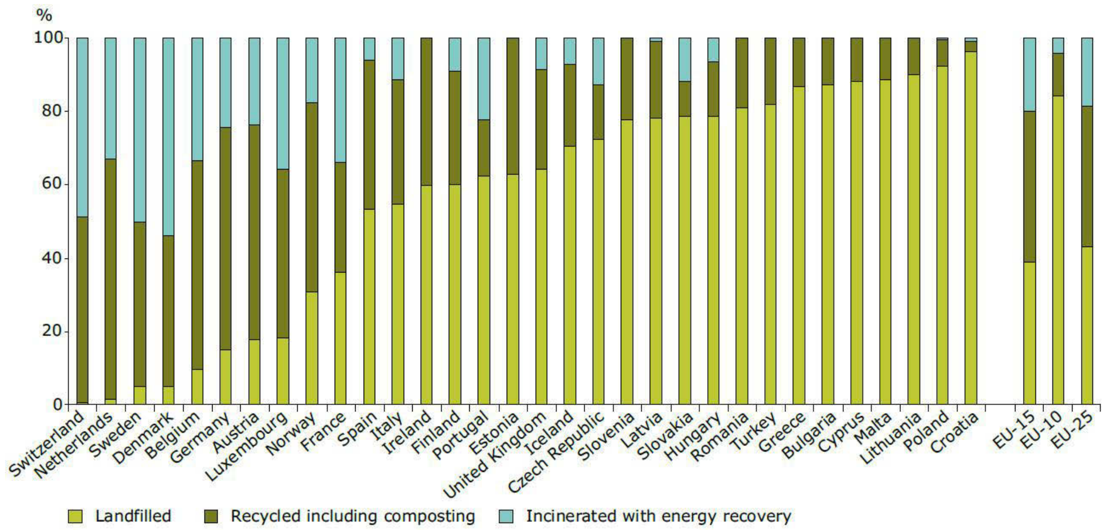

Figure 17: Rate of recycling versus incineration with energy recovery of municipal waste, 2005 for the EU (European Environment Agency 2007)

Feedstocks used predominantly in current EfW facilities include municipal solid waste (MSW), refuse derived fuel (RDF), sewage sludge, tyres and wood waste. Especially equipped plants are able to accept hazardous waste streams, such as chemical or medical waste, without exceeding the stringent emission limits set by the European Union (European Parliament and Council 2010) and other authorities. While MSW streams can have a biogenic content of up to 50% (Gohlke & Spliethoff 2007), the use of wood waste and RDF is of particular interest as wood waste is a fully renewable fuel and RDF does maximise recycling efforts, has a significant renewable component and is more consistent than MSW. This has positive flow-on effects in the power plant including better combustion performance, higher efficiency and simplified flue gas cleaning (Chang, Chen & Chang

1998). The recovery of wood waste and RDF from municipal, commercial and industrial waste streams is well established with many units in commercial operation. RDF is not a precisely defined fuel and therefore the term 'solid recovered fuels' was introduced. Solid recovered fuels have defined quality specifications in regards to material origin and properties (Rotter et al. 2011). However, the term RDF is still widely used and many literature sources do not yet use solid recovered fuels.

Currently, a variety of thermal conversion technologies in different stages of technological maturity are available. They include combustion, gasification, plasma and pyrolysis, as well as mixtures of these (Lamers et al. 2013). Currently, grate combustion systems dominate the EfW market with around 2,000 references worldwide, with plant capacities from 0.3-150 MWth, various fuel types, significant operational experience, and a variety of technology suppliers (Lamers et al. 2013; Spliethoff 2010). To raise feedstock conversion efficiency some systems have been hybridised with natural gas through external EfW steam superheating in dedicated superheaters, such as 28 MWe Holstebro plant in Denmark (Andersen, Oksen & Olesen 1992; Babcock & Wilcox Vølund A/S 2008), or in adjacent combined cycle plants. These include the 88 MWth Mainz plant in Germany (Entsorgungsgesellschaft Mainz mbH 2007) and a 93.2 MWe Bilbao plant Spain (Gohlke & Spliethoff 2007). Some fluidised bed systems exist for MSW, such as an 800 t/d plant in Cixi China (Huang, Chi & Themelis 2013) and RDF, such as the 30 MW cogeneration plant in Eisenhüttenstadt Germany (EnBW Energie Baden-Württemberg AG 2009). However, despite the size of these reference plants and their technical benefits, such as improved efficiency and reduced excess air requirements, the smaller number of reference plants leads to a lower maturity than grate systems.

Gasification systems offer technological and environmental benefits over combustion systems as some technologies are able to produce a synthesis gas that is compliant with gas engine and turbine specifications, a vitrified non-leaching slag without additional treatment, improved waste volume reduction, and lower air requirements for the conversion process (Arena 2012; Lamers et al. 2013). EfW gasification technologies have to be separated into gasification/combustion and gasification technologies (Lamers et al. 2013). Gasification/combustion, also known as staged combustion, uses gasifiers to produce a raw gas that is burnt in a boiler connected to a conventional Rankine cycle power plant. Gasification technologies, also referred to as true gasification, clean the produced raw gas to a synthesised gas suitable for high efficiency conversion in gas engines and turbines. A variety of commercial gasification/combustion plants operate on RDF worldwide, including a 50 MWe Lahti plant in Finland (Lamers et al. 2013), a 33 MWe

Albano plant in Italy (JFE Engineering 2013), a 20 MWe Fukuyama plant in Japan (JFE Engineering 2011), and a 6.7 MWe Greve plant in Italy (Granatstein 2003). There are fewer gasification plants with gas engines or turbines. Most of them are in Japan, and many of them use the Thermoselect technology. These include the 1.5 MWe Chiba plant and the almost twice as large Mizushima plant which provides synthesis gas to an adjacent processing plant (Sumio, Masuto & Fumihiro 2004). The Thermoselect technology is a combination of pyrolysis followed by high temperature gasification at over 1,200°C, which decomposes the MSW, RDF and other waste feedstocks into a synthesis gas (consisting mainly of hydrogen and carbon monoxide) as well as vitreous slag and metals which can be recycled or used for construction purposes (Sumio, Masuto & Fumihiro 2004). A 6.5 MWe plant using a different pyrolysis/gasification technology was commissioned in March 2013 in the U.K. (Reece 2013) but long-term operational data is not yet available. In total less than 100 waste gasification units have been built worldwide and not all of them have been commercial successes (Lamers et al. 2013), which is a key reason why gasification systems do not currently have a larger market share.

Plasma gasification further raises the process temperature to over 2,000°C by using an electric arc and thereby converting the feedstock predominantly to hydrogen and some carbon monoxide suitable for gas engine and turbine operation. This process also produces vitreous slag. A reference plant exists for asbestos treatment in France (Europlasma Group 2014) and the largest plant yet, producing 12 MWe, commenced operation in 2012 also in France (Waste Management World 2012). Globally around 15 units, including pilot plants, exist with the majority of them being in Japan (Lamers et al. 2013). Plasma systems are beneficial in regards to high synthesis gas quality and waste volume reduction but the high capital (CapEx) and operational expenditures (OpEx) as well as plant complexity have limited technology uptake to date.

In pyrolysis plants the feedstock, typically RDF, is heated to above 300°C in the absence of oxygen and converts to synthesis gas, oil, char, and recyclable materials. The oil and synthesis gas is suitable for high efficiency power generation in gas engine and turbine plants and the metals are recyclable. The first large test unit, in Fürth Germany, was unable to achieve a continuous operation while another unit in the USA never met the air emission standards and was decommissioned in 2009 (Lamers et al. 2013). However, due to higher efficiency expectations around 25 plants were built worldwide but the failures in the first units damaged the technology’s reputation significantly and little information is available about the other reference plants (Lamers et al. 2013).

Technology distribution in the EfW market is similar to CSP where the less efficient but mature parabolic trough technology using thermal oil as the primary working fluid dominates the market, just as grate combustion systems do in the EfW market. Efforts are being made to increase the efficiency of combustion systems through the use of fluidised beds combustion systems, not dissimilar to the development of direct steam or molten salt parabolic trough systems. The more efficient gasification technologies are able to raise cycle efficiency, further reduce emissions, and produce valuable secondary products, such as fuels. This is comparable to the way in which solar tower and Fresnel systems are currently proving their techno-economic viability and are increasing their market share. Currently pyrolysis systems have, despite technical benefits such as char production, the least market penetration and are comparable to CSP dish systems, which also offer high technical potential but have had little commercial success to date. The future development of EfW technologies will strongly depend on the technical and commercial success of recent reference plants as well as government priorities in regards to electricity, heat, material recovery, and fuel production from waste materials, as well as emissions.

2.3.2 Energy from biomass

Since the industrial revolution biomass has been used for power generation purposes and in 2013 biomass was, after hydro and wind, the third-most important source of renewable electricity worldwide with an output of 396 TWh (International Energy Agency 2013). Despite currently having a smaller installed capacity than PV, it is projected that by 2018, biomass plants will generate 560 TWh – significantly more electricity than PV which is expected to provide 368 TWh (International Energy Agency 2013). The reason for this is the high capacity factor of biomass plants reaching 8,000 operational hours per year or 91.3%.

Feedstocks for energy from biomass (EfB) are versatile. They include wood, bark, bagasse, agricultural crops (e.g. straw and rice husk), and energy crops (e.g. miscanthus). With some of these fuels potentially competing with food production (Baffes 2013; O'Connell et al. 2009) the use of algae is being investigated more closely for electricity and fuel production (Jonker & Faaij 2013; Rashid et al. 2013; Resurreccion et al. 2012) and while several test facilities exist no commercial units are operational yet.

Depending on fuel, the capacity and conversion technology cycle efficiencies for current EfB plants vary from 15–35% (Stucley et al. 2012). Biomass integrated combined cycle plants using gasification or pyrolysis have the potential to raise cycle efficiency to over 40% through the use of a Brayton cycle and a bottoming Rankine cycle but no reference plants exist yet.

The capacities of EfB plants range from small industrial heating systems to the world's largest plant, the Polaniec power plant in Poland, which has an output of 205 MWe (GDF SUEZ 2013). However, the comparatively low calorific value of biomass compared to black coal or natural gas leads to high transport costs, which usually limits plant size to 30 MWe. Larger plants are only feasible when co-located with saw, pulp and paper, and sugar processing facilities, or when using wood pellets and briquettes to increase the feedstock's calorific value. Of increasing interest worldwide is biomass co-firing in utility scale power plants as it is a low-cost option for the integration of renewable energy (Lempp 2013). Case studies have already been investigated in Australia (Meehan 2013). Worldwide, several units blend solid biomass and coal prior to combustion such as in the 590 MWe Avedore power station in Denmark (Stucley et al. 2012), or they gasify biomass and burn the raw gas in parallel to the main fuel, such as in the 560 MWe Vaskiluodon Voima Oy power station in Finland (Metso Corporation 2011). The choice of the co-firing system depends on the feedstock quantity and quality as well as the design of the coal plant (Lempp 2013; Tadros et al. 2009).

The conversion technologies for EfB are essentially the same as for EfW plants except that: a) plasma technologies are not used, as EfB plants do not have to cope with significant plastic compounds; and b) that gasification and pyrolysis is more advanced for biomass feedstocks because it is less heterogeneous than waste feedstocks. Grate combustion systems are the ones most established in EfB plants (Spliethoff 2010) but a variety of fluidised bed systems are in operation with benefits in regards to cycle efficiency and emissions (e.g. 20 MWe Königs Wusterhausen plant in Germany) (Lahoda, Arndt & Hanstein 2006). Also a variety of commercial gasification/combustion references exists worldwide with capacities reaching 140 MWth (Metso Corporation 2011) and gasification engine systems with capacities of 6 MWe (Spectrum Magazine 2009). Unlike EfW pyrolysis the production of biochar is an important development as it can be used for carbon sequestration, for soil enhancement, and as a renewable feedstock for metallurgical processes (Garcia-Perez, Lewis & Kruger 2010; Sohi et al. 2009). A variety of demonstration plants exist, such as the Somersby facility in Australia which is capable of processing 300 kg of feedstock per hour to produce biochar and 200 kW electricity (Pacific Pyrolysis 2010). However no commercial plants are operational yet. The variety of possible products is promising for markets in the future but current demonstration facilities have to further prove the technical viability of this approach before the first commercial units can test the technical and economic expectations.

The future for EfB strongly depends on the sustainable production of biomass feedstocks without impacting food production. Options exist to avoid this conflict, including the co-location of food and energy production or the use of waste materials from agriculture for energy generation. However, the right policy settings are required to ensure the existence of these conditions.

2.3.3 Australian market

Municipal solid, commercial, industrial, and construction and demolition waste streams going to landfill in 2006–07 amounted to 21 million tonnes (t), which equals 48% of total waste generation (Environment Protection and Heritage Council 2010). In Australia the recycling rate for MSW was 40% in 2006–07 (Environment Protection and Heritage Council 2010) which is similar to Sweden's in 2005 (see Figure 17 on page 25), with the noticeable difference that Sweden landfilled less than 5% of its MSW and used the majority for energy recovery. In Australia 60% of MSW was landfilled without any energy recovery. Considering that in Australia up to 72% of this waste stream consists of organic materials (Environment Protection and Heritage Council 2010), the potential for biochemical treatment of putrescible waste (Stucley et al. 2012), and for thermal treatment plants using wood waste and RDF is significant. Some plants for biochemical treatment already exist in Australia (Stucley et al. 2012).

In 1972 the Waterloo waste incinerator commenced operation in Sydney but it was decommissioned in 1993 due to public protests which were due in part to the plant's emissions being 12 to 38 times larger than permitted emission limits on various occasions (Sharp et al. 2004). The plant sparked protests from the beginning and opposition increased due to a plant failure in 1975 which caused it to shut down for several months (Sharp et al. 2004). Due to this experience the reputation of EfW in Australia was harmed and currently only pulp and paper mills operate EfW cogeneration facilities using rejects from their processes as well as wood waste (e.g. Visy Paper) (Visy Industries Australia 2012). One designated RDF production facility exists in South Australia (Watson & Peterseim 2010) which supplies feedstock for co-firing in a cement kiln (Adelaide Brighton 2007). Recently, a proposal for a 15 MWe (gross) RDF gasification/combustion plant in Port Hedland, Western Australia, received environmental approval (Environmental Protection Authority 2013) and others are being developed, such as a 75 MWe proposal for Tumut in New South Wales (Kitney 2011). However, no project has yet commenced construction.

In recent years almost all states have conducted studies or prepared policies for EfW facilities, including the Australian Capital Territory (Lokuge & Loftus 2010), Western

Australia (Fanning 2013), South Australia (Warren et al. 2013), Victoria (Environmental Protection Agency Victoria 2013), and New South Wales (Environmental Protection Agency NSW 2013). These are steps towards the implementation of such facilities in the future.

Based on the experience of the Waterloo incinerator in Sydney the only option to obtain community acceptance for new EfW plants in Australia is early community engagement, compliance with stringent international emission limits (e.g. the Environmental Protection Agency recent NSW (2013) adopts the EU emission limits in its recent EfW draft policy), and the use of materials downstream of a recycling process. Currently, the wholesale electricity price in the NEM and the REC price are insufficient to make EfW plants economically viable in Australia. For these plants to be profitable they would require another revenue source which could be provided through waste disposal levies. These levies would also encourage the diversion of waste from landfill.

In Australia sufficient lignocellulosic biomass is available from current agricultural and forestry production systems to annually generate 35 TWh of electricity (Farine et al. 2011), which is equal to 14% of the 2011–12 Australian electricity generation of 254.7 TWh (Bureau of Resources and Energy Economics 2013). Considering the integration of new eucalypt plantings incorporated into agricultural landscapes this potential could increase by another 20.2 TWh/year (Farine et al. 2011). In 2012 the total installed capacity of wood waste and bagasse power plants was 573 MWe (see Table 1) of which 206 MWe has commenced operation since 2001 (Biomass Power & Thermal Magazine 2011; Stucley et al. 2012). Australia’s projected bioelectricity generation for 2012–13 was 2 TWh (Bureau of Resources and Energy Economics 2013) and assuming the fuel mix in Table 1 as well as identical capacity factors, bagasse and wood waste could have generated 1.3 TWh, of which 0.9 TWh could have been produced from bagasse in Queensland alone. Comparing the current electricity generation and the potential from current agricultural and forestry production systems highlights the significant growth potential for EfB in Australia. However, the electricity production from all bioenergy sources in 2034–35 is predicted to be only 7 TWh (Bureau of Resources and Energy Economics 2013).

Due to the high carbon intensity of Australia’s generation assets, particularly coal, currently available lignocellulosic biomass feedstocks are best used for electricity generation rather than for biofuels. Using biomass for electricity generation could yield 30 million tonnes CO_2 equivalent greenhouse gas mitigation, whereas if it is used to produce biofuels it would only provide 9 million tonnes CO_2 equivalent greenhouse gas mitigation (Farine et al. 2011). Assuming increasing renewable and natural gas fired generation in the future, this benefit will decrease over time but the significant greenhouse gas mitigation difference is likely to favour biomass for electricity generation over biofuels for many years to come.

Table 1: Biomass generation capacity in MWe per state and fuel in 2009 (Stucley et al. 2012) updated with the recently commissioned 36 MWe Mackay plant using bagasse in Queensland (Biomass Power & Thermal Magazine 2011)

State	Biogas	Bagasse	Wood waste	Other bioenergy[5]	Total
New South Wales[6]	73	81	42	3	199
Victoria	80	-	-	34	114
Queensland	19	413	15	4	415
South Australia	22	-	10	-	32
Western Australia	27	6	6	63	102
Tasmania	4	-	-	-	4
Northern Territory	1	-	-	-	1
Total	226	500	73	104	903

With the low average wholesale electricity price in Australia biomass co-firing has been investigated as a low-cost approach, LCOE below AU$ 50/MWh (Meehan 2013), to integrating renewable energy with coal plants. Tests were carried out at several power stations in New South Wales and Queensland (Meehan 2013) and while Delta Electricity and Macquarie Generation co-fired low levels of biomass materials commercially for several years they stopped due to issues around fuel availability and economics (McEvilly, Abeysuriya & Dix 2011). Plans were made to replace up to 20% of coal consumption with biomass at Wallerawang but the necessary technical changes required have not been made yet (McEvilly, Abeysuriya & Dix 2011). Currently, only smaller units, such as the 114 MWe Worsley multi-fuel plant in Western Australia and the 55 MWth Tumut plant in New South Wales, co-fire biomass to provide electricity and process heat (Meehan 2013).

Biomass pyrolysis is being discussed in Australia as an option to generate electricity and simultaneously biochar to increase soil carbon. Agriculture and horticulture are important business sectors in Australia and improving soil carbon would be beneficial, particularly with some waste materials from these industries, such as wood waste and stubble, being suitable for biochar production (Cox et al. 2012). Since 2006 a test facility has been operational in New South Wales (Pacific Pyrolysis 2010). In 2011 the Victorian Government

[5] Unspecified biomass and biodiesel

[6] Includes the Australian Capital Territory

allocated AU$ 4.5m to co-fund a commercial biochar plant in Melbourne (Manning 2011), and in 2012 the federal government allocated AU$ 4.3m for another commercial facility in New South Wales (Saunders 2012). Unfortunately, the construction of commercial plants has not commenced yet and little information has been available.

Similar to EfW, if new EfB plants were to be constructed they would require another revenue source in addition to the income from current wholesale electricity and RECs. Alternatively, wholesale electricity and REC prices would need to be higher. Process heat is an attractive revenue stream and the existing cogeneration plants adjacent to sugar as well as pulp and paper processing plants benefit from the generation of both electricity and heat. This should be a priority for the development of future EfB plants. Continuous feedstock supply is crucial for EfB projects, and this requires a well-managed supply chain to ensure operation throughout the seasons and potentially periods of drought. However, these issues have been successfully managed in existing plants in Australia and overseas and the comparatively low cost of EfB, compared to solar, geothermal and offshore wind, as well as its high capacity factor make it a promising renewable energy source to contribute to Australia's 2020 renewable energy target.

2.4 CSP hybrid benefits & challenges

Currently, CSP is considered a higher cost renewable energy source than wind or PV (International Energy Agency 2013) but its ability to be integrated into existing natural gas and coal power plants has significant cost reduction potential and studies have confirmed that several power plants in Australia and the USA meet hybridisation criteria, such as high DNI and high available plant capacity (Meehan 2013; Turchi et al. 2011). However, significant cost reductions are possible not only in retrofit scenarios but also in new CSP hybrid plants using fossil and renewable fuels. For example CSP-natural gas hybrids with an LCOE of US$ 168/MWh compared to US$ 180/MWh for CSP-only plants (Turchi & Ma 2014) and CSP-biomass hybrids which can be economic at AU$ 145/MWh compared to AU$ 200/MWh for CSP-only plants (Peterseim et al. 2014a). Such reductions are highly important to increase the CSP market share as they enable the reduction or even elimination of government incentives. In addition they make the projects more attractive to private investors.

Due to the need for economies-of-scale to attain lower specific costs (IRENA 2012) capacities for most CSP-only plants are between 10 and 280 MWe to ensure commercially viability. Large capacities coupled with technology and TES-dependent specific costs of AU$ 4.6-7.4m/MWe (Lovegrove et al. 2012) result in hundreds of millions or even billion-dollar project budgets. For example the 50 MWe Andasol plant in Spain has a budget of € 300m (Solar Millennium AG 2006), 280 MWe Solana plant has a budget of US$ 2b (NREL 2014d), and the 392 MWe Ivanpah plants has a budget of US$ 2.2b (NREL, 2013b). Such large projects are not only difficult to finance but also incur a higher risk premium than kilowatt-scale PV systems. However, CSP hybrids can have significantly smaller capacities, and this reduces budget size and financial risk as shown in the 9.3 MWth CSP feedwater heating augmentation system at Liddell power station in Australia (Novatec Solar GmbH 2012a). Without CSP expertise, power plant owners and financiers are likely to favour technologies they know over CSP when deciding on new generation assets, assuming similar financial conditions. Initially building smaller CSP plants would allow the developers, and also equipment suppliers, to gain local CSP expertise without committing too much capital. The establishment of smaller plants will also enable plants to upskill staff in parallel to day-to-day business, and to build the confidence needed to subsequently operate larger CSP installations (Peterseim et al. 2014d).

Compared to lower cost but also lower average capacity factors for wind and PV generation, 20% for PV and 30% for wind (Hearps & McConnel 2011), CSP can reach high capacity factors by incorporating TES, e.g. 74% demonstrated in Gemasolar plant (SENER

2014). However, TES was at AU$ 90/kWh (thermal) in 2011 CapEx intensive (Hinkley et al. 2011) and hybrid systems can lower plant costs by reducing or even avoiding high cost TES investment. With TES costs expected to decrease to AU$ 22/kWh (thermal) by the end of this decade (Hinkley et al. 2011) this advantage of CSP hybrid developments will decrease but not disappear due to the inherently lower cost and lower complexity of integrating a EfB, EfW or natural gas steam system. Additionally, CSP hybrid plants can meet variable daily electricity demand with the host plant operating constantly and the CSP component providing additional capacity during the day when electricity demand and prices are typically significantly higher, as demonstrated by two plant proposals in Australia, the 30 MWe CSP–EfB hybrid for Griffith (Peterseim et al. 2014c) and the 35.5 MWe CSP-multiple feedstock hybrid for Swanbank (Peterseim et al. 2012a).

Typically, CSP-only plants require a DNI of at least 2,000 kWh/m^2/year to be commercially viable but CSP hybrid plants have been built in locations with only 1,800 kWh/m^2/year (Morell 2012) and have been considered at even lower DNI levels of as low as 1,691 kWh/m^2/year (Pérez & Torres 2010). Moving CSP out of remote arid desert/semi desert regions closer to agricultural/urban regions expands potential CSP sites, reduces transmission losses, potentially avoids new and capital intensive transmission infrastructure, and enables access to back-up fuel sources (e.g. agricultural and urban waste feedstocks). Being close to load centres also increases opportunities for highly efficient cogeneration as well as industrial heating/cooling applications. The use of biomass and waste feedstocks in larger hybrid plants increases, albeit involving some part-load operation, the plant’s cycle efficiency compared to a EfB- and EfW-only facilities and thereby increases annual generation (Peterseim et al. 2014a).

All power projects create employment during construction and operation but renewable energy systems have higher socio-economic benefits than fossil fuel powered plants (Caldés et al. 2009; Wei, Patadia & Kammen 2010). The employment benefits are very valuable to the local communities but they also contribute to operational cost. Efforts are being made to minimise capital and operational cost, as in fossil fuel fired power plants, and in the future the employees required, personnel per MWh, to operate renewable energy plants is likely to decrease with more learning experience. Like CSP-only plants, CSP–EfB and CSP–EfW hybrids can increase direct and indirect employment through ongoing feedstock collection, processing and transport. For EfB facilities this is far more significant than the direct employment needed to operate the actual power plant (Thornley, Rogers & Huang 2008). This also broadens community involvement and increases long lasting acceptance of a power generation asset. In addition to primary benefits, such as renewable energy or local employment, CSP–EfB and CSP–EfW hybrids can provide secondary benefits such as bushfire hazard reduction through biomass collection and landfill diversion.

Despite the numerous benefits of CSP hybrid plants they face some additional challenges compared to CSP-only installations. A potential challenge is the perceived technology risk associated with new power plant concepts and the limited number of CSP hybrid plants already in operation and currently under construction (see Section 2.5). Although individual CSP components have been commercially proven, the various hybrid concepts, when first proposed, will incur higher financing costs due to the need for risk mitigation. In addition to the limited operational expertise with CSP hybrid plants, environmental approval processes and technical standards might be additional and time consuming obstacles for first local reference plants.

Resource security is another key consideration as CSP hybrid plants not only require a sufficiently high DNI but also need a continuously available second energy source, such as natural gas or biomass. Also these resources have to be secured contractually, which is a significant challenge over the circa 30 year power plant lifetime. Identifying sites that fulfil the resource criterion in addition to standard requirements, such as transmission infrastructure, water supply, and road infrastructure is not trivial and increases the work required for project development. Moreover, current transmission infrastructure in Australia is designed for centralised power generation (Dopita & Williamson 2009). This makes the grid connection of distributed generators, which comprises most renewable energy systems including CSP–EfB and CSP–EfW hybrid plants, more complicated and costly compared to utility scale CSP-only plants with capacities of more than 100 MWe.

Despite the aforementioned cost reductions of CSP hybrid plants their electricity costs would still exceed the combination of the current average wholesale electricity price of AU$ 50/MWh (RepuTex 2013), which includes a carbon price of AU$ 24.15/t CO_2 (Australian Government 2011), and the REC price of AU$ 30/MWh (RepuTex 2013). Economic viability is a significant barrier for countries with low wholesale electricity prices, such as Australia (Bureau of Resources and Energy Economics 2013) and plant siting is key. It is important to identify locations where network constraints exist and competing energy sources have higher costs.

Apart from technical and economic challenges, socio-cultural factors have to be considered too. Proposals for new gas and coal fired power plants with a CSP contribution and CSP retrofits to existing fossil fuel plants can face community opposition as the CSP component could be perceived as "greenwashing" of fossil electricity generation. The hybridisation of fossil fuel and CSP power generation is currently seen as a cost efficient option for the transition to a low carbon future but it needs to be borne in mind that such plants could also be used to unnecessarily extend the transition process. This is a particular concern when the CSP contribution to the overall hybrid plant output is small.

In addition, the use of controversial fuels, such as coal seam gas in such plants is likely to cause community concern. For CSP–EfB and CSP–EfW hybrids, community acceptance issues could arise from concerns around ongoing debates about fuel vs. food, material vs. energy recovery, native forests for bioenergy, and land use changes. These points can be addressed through appropriate feedstock selection (Farine et al., 2011) and require active community engagement strategies.

2.5 CSP hybrid plants

A variety of CSP hybrid plants exist and are being investigated. To cover the diversity of the field this section provides an overview of CSP–EfB and CSP–EfW and other CSP hybrid options. These include fossil and renewable hybrids with industrial- to utility-scale power generation capacities. Currently, most CSP hybrids involve the use of fossil fuels but fully renewable hybrids exist and are under development.

Figure 18 shows the two main CSP integration options: a power top-up and a fuel saver. Fuel saver options are ideally used in carbon intensive power generation assets such as coal fired power stations, while the power top-up option provides additional capacity during daytime periods of high demand and high prices. The decision about whether to adopt the power top-up or the fuel saver model depends not only on the fuel type but also on local market conditions, such as electricity demand, price structure, carbon pricing, power plant operation, and the overall renewable energy contribution to the network.

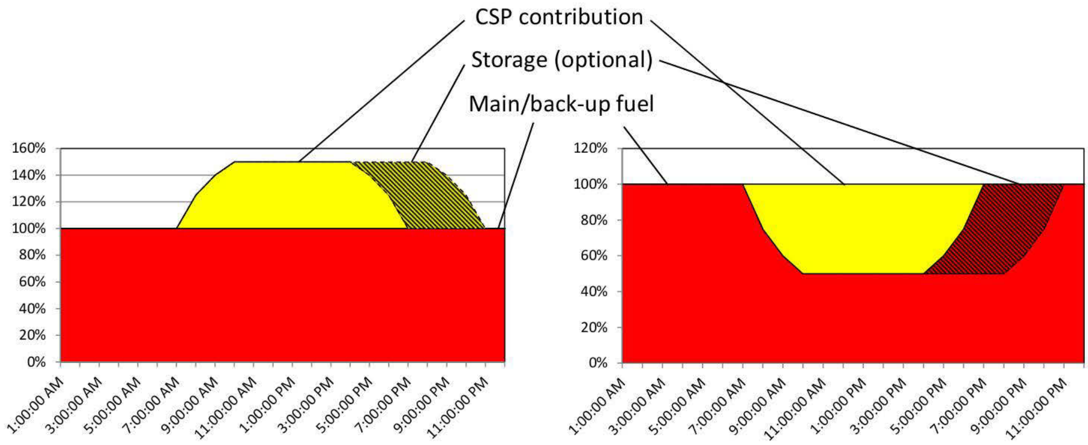

Figure 18: CSP power top-up (left) or fuel saver (right) option

2.5.1 CSP-Natural gas

Currently, most CSP hybrid plants in the world use natural gas as it is a promising option to further lower the carbon intensity of natural gas fired power plants while also reducing consumption of an increasingly expensive fuel. The CSP contribution to the annual generation of current reference plants is typically small but technical concepts for high solar share CSP hybrids exist.

2.5.1.1 Commercial references

Several integrated solar combined cycle (ISCC) plants are already in operation worldwide with CSP equivalents of 75 MWe at the FPL Next Generation plant in the USA (Florida Power & Light Company 2010) (see Figure 19a), 20 MWe at the Hassi R'Mel plant in Algeria

(Abengoa 2013), 20 MWe at the Ain-Beni-Mathar plant in Morocco (Abengoa 2013), and 19.2 MWe at the Kuraymat plant in Egypt (Brakmann et al. 2009). These plants use parabolic through systems with thermal oil to provide high pressure saturated steam to the heat recovery steam generators (HRSG) of the combined cycle power plants for further superheating and have no TES. The only exception is the 5 MWe Archimede ISCC plant in Italy, which has TES and uses parabolic troughs with molten salt to generate steam parameters identical to the HRSG of the combined cycle plant (Falchetta et al. 2009). More ISCC plants are under construction in Mexico (Abengoa 2013), the USA (U.S. Department of Energy 2013b) and Canada (SkyFuel 2012).

In current ISCC plants, the CSP portion of the total plant capacity is usually relatively small at less than 10%. The only CSP–natural gas hybrid plant with a CSP share of more than 80% of installed capacity is the 100 MWe Shams One plant in the United Arab Emirates (Goebel & Luque 2012) shown in Figure 19b. The Shams One plant consists of a conventional parabolic trough with thermal oil and it has natural gas fired external superheaters to increase the 380 °C CSP steam to 540 °C thereby increasing cycle efficiency (Goebel & Luque 2012). The higher efficiency reduces the solar field size which is the most capital intensive component of a CSP plant.

Figure 19: a:75 MWe equivalent CSP steam boost to Martin Next Generation power station in the USA (Florida Power & Light Company 2010) and b: 100 MWe Shams One plant (Goebel & Luque 2012)

Almost all CSP plants have a natural gas fired heaters but these are not designed to provide full plant capacity or continuous operation. Rather, they are for plant start-up, generation stabilisation, and emergency operation. They are therefore not considered CSP hybrids. However, full capacity gas fired boilers or heaters in parallel to the CSP component is a technical option, and such a unit is in fact installed in the Shams One plant to ensure supply availability at all times (Goebel & Luque 2012). However, the natural gas conversion efficiency of these systems is slightly lower than in a combined cycle plant. To limit gas consumption in back-up systems, Spain limited the natural gas contribution to 15% and the

Shams One plant is expected to provide only 4% of annual generation through the gas fired heater system (Goebel & Luque 2012).

2.5.1.2 Concepts

In addition to the reference plants available, a variety of other concepts exist for CSP natural gas hybrid Rankine cycle plants. Several studies analyse and outline ways of optimising the currently dominant ISCC concept with parabolic trough plants using thermal oil to provide saturated steam to the HRSG's high pressure steam cycle (Baghernejad & Yaghoubi 2010; Dersch et al. 2004; Horn, Führing & Rheinländer 2004; Kelly, Herrmann & Hale 2001; Ugolini, Zachary & Park 2009). To increase the annual CSP contribution, adaptations were suggested to include steam reheating from parabolic trough (Kane et al. 2000) and Fresnel fields (Siva Reddy, Kaushik & Tyagi 2012). To reduce the investment needed and to simplify CSP integration, parabolic trough systems with direct steam generation are being investigated to provide saturated steam to the high pressure steam cycle of the HRSG (Montes et al. 2011) and to provide superheated steam directly to the steam turbine (Nezammahalleh, Farhadi & Tanhaemami 2010). Similarly, the use of CO_2 as the heat transfer fluid in the solar field (Cau, Cocco & Tola 2012) and the use of CO_2-steam cycles (Gou, Cai & Hong 2007) have been investigated but both technologies still require significant R&D work before commercialisation.

Further concepts using solar towers with direct steam and molten salt were investigated as ways to provide high pressure superheated steam to the steam turbine including CSP steam reheating (Peterseim et al. 2012c, 2013a; Ugolini, Zachary & Park 2009). One such example is shown in Figure 20a and apart from providing high cycle efficiencies and high solar shares when incorporating TES, the concept allows the independent operation of the CSP and natural gas plants. A recent comparison of ISCC plants with parabolic trough and solar tower systems confirmed that solar towers have a higher power production and efficiency potential than trough systems (Franchini et al. 2013). To maximise overall cycle efficiency and provide drinking water, ISCC concepts coupled with seawater desalination have been investigated (Alrobaei 2008).

Most ISCC designs have a low CSP contribution to annual generation due to a) the lack of TES and b) cycle efficiency reductions at times when CSP is not contributing to steam turbine operation. One CSP hybrid concept with a greater than 50% CSP share of annual generation uses a gas turbine in parallel with a parabolic trough plant, either with thermal oil or molten salt, with the exhaust energy from the gas turbine being recovered by the solar field's primary working fluid cycle (Turchi & Erbes 2011; Turchi & Ma 2014). The concept is being analysed with and without TES and has the benefit of very flexible power generation due to the quick start-up capabilities of gas turbines and the highly efficient use of natural gas in the gas turbine and heat recovery systems.

Unlike the use of CSP and natural gas in Rankine cycle plants, extensive research into solarised Brayton cycles is ongoing due to their high efficiency and lower cost prospects. Rather than thermal oil, molten salt or direct steam systems Brayton cycle applications heat air after the compressor part of the gas turbine to 800–1,200 °C (Ávila-Marín 2011) and re-inject it with natural gas into the gas turbine's combustion chamber. The first detailed studies go back to the 1990s with continuous concept improvements and prototypes (Ávila-Marín 2011) until in 2012 the first pre-commercial 4.6 MWe Solugas tower, shown in Figure 20b, commenced operation in Spain (Quero et al. 2013). Currently, prototype and demonstration plants operate as open cycle units but the aim is to increase efficiency by adding a bottoming Rankine cycle and TES.

Figure 20: a: 228 MWe solar tower ISCC concept (Peterseim et al. 2012c) and b: 4.6 MWe Solugas tower in Spain (Quero et al. 2013)

A different approach to integrating CSP with natural gas is the injection of steam from a CSP system into the gas turbine's combustion chamber (Livshits & Kribus 2012). In plants that do not use CSP this is a common technology for improving the performance of open and combined cycle plants. It works by taking steam from the HRSG. CSP could also be used to cool the inlet air of gas turbines via absorption chillers to avoid performance degradation at high ambient temperatures (Bellac & Destefanis 1999; Popov 2014). This concept is also common in non-CSP plants and it works by using steam from the HRSG to operate the absorption chiller, or by using electricity from the generator to operate mechanical chillers.

Currently, the least mature but technically promising CSP-natural gas hybrid concept is the thermochemical conversion of natural gas to a higher calorific value synthesis gas, predominantly consisting of hydrogen. Research on this concept commenced in the 1980s and since then steam reforming of natural gas has been successfully demonstrated in a 300 kWe gas turbine test facility in Australia (Stein et al. 2009). However, with CSP only providing the heat for the thermochemical process, the solar energy content of the synthesis gas is limited to 26% (Stein et al. 2009). Solar tower and dish systems have been favoured in thermochemical concepts due to their ability to provide high temperatures and therefore high conversion efficiency. However the greater maturity of parabolic trough systems has led to recent thermochemical investigations of this collector type (Bianchini, Pellegrini & Saccani 2013). Mature thermochemical CSP-natural gas hybrids would allow the use of highly efficient combined cycle plants and lower cost thermochemical energy rather than sensible heat storage.

2.5.2 CSP-Coal

The hybridisation of CSP with coal, particularly in retrofits, is widely discussed as a low-cost option for reducing the greenhouse gas intensity of these assets while simultaneously progressing knowledge about the construction and operation of CSP (Jamel, Abd Rahman & Shamsuddin 2013; Meehan 2013; Siros et al. 2012; Turchi et al. 2011). However, CSP retrofits have to be considered carefully on a project-by-project basis as the CSP contribution to the annual generation is typically small and the renewable asset could be used as a pretext for extending the operating life of the station. Section 4.1 discusses this contentious issue in more detail based on two reference plants in Australia.

2.5.2.1 Commercial references

Currently, the only operational CSP-coal hybrid plant worldwide is the 9.3 MWth feedwater heating augmentation facility at the 2 GWe Liddell power station in Australia (Macquarie Generation 2012; Novatec Solar GmbH 2012a). The solar field is providing saturated steam at 55 bar to the coal plant’s high pressure feedwater heater (Lovegrove et al. 2012; Novatec Solar GmbH 2012a). Another 4.4 MWth feedwater heating augmentation system was in operation for one year at the 49 MWe unit 2 of the Cameo power station, in the USA but it has since been decommissioned (Xcel Energy Inc 2010). The largest plant yet, a 44 MWe equivalent solar boost to the 750 MWe Kogan Creek power station – shown in Figure 21 – in Australia is designed to provide steam to the cold reheat line of the power plant. It is expected to come online in 2015 (NREL 2014c). A second project under construction is the 5 MWe equivalent solar boost to the 156 MW Unit 4 of the Sundt power station in the USA

(AREVA Solar 2012c). Except for the Cameo hybrid plant which uses the parabolic trough technology, all of these plants use a Fresnel solar field and no reference plant has TES.

Figure 21: Kogan Creek Solar Boost project under construction as per October 2013[7]

2.5.2.2 Concepts

A variety of concepts exist for the hybridisation of CSP with coal. Most focus on feedwater heating and steam supply into the cold reheat line, with references already in operation and under construction as shown in the previous section. Feedwater heating options for lignite and black coal power plants receive most attention, with several case studies worldwide identifying their carbon emission reduction and low cost potential (Bakos & Tsechelidou 2013; Hu et al. 2010; Meehan 2013; Mills, Lièvre & Morrison 2003; Pierce et al. 2013; Popov 2011; Siros et al. 2012; Suresh, Reddy & Kolar 2010; Turchi et al. 2011). Although the world's largest CSP-coal hybrid under construction at the Kogan Creek power station uses CSP to provide additional steam to the cold reheat line (CS Energy 2011; NREL 2014c) little research has been carried out in this field. However a recent report identified further opportunities for this CSP hybrid option combined with feedwater heating in Australia (Meehan 2013). Two studies on the augmentation of CSP to fossil fuel plants in Australia and the USA concluded that steam from a conventional parabolic trough plant with thermal oil could be integrated before the coal boiler's superheater, while steam from solar towers could be directed straight into the high pressure steam turbine section of subcritical power plants (Turchi et al., 2011, Meehan, 2013). Principally, parabolic trough plants with molten salt, as demonstrated in the Archimede facility in Italy (Falchetta et al. 2009), would also be capable of providing CSP steam to the high pressure steam section turbine of a subcritical coal fired power plant. The use of CSP to provide supercritical steam to a coal fired power station has not been investigated yet.

[7] http://kogansolarboost.com.au/news/photo-gallery/?album=1&gallery=1, accessed 04 April 2014

A more experimental concept is the possible use of CSP to provide steam to the reboiler of a carbon capture plant in coal fired power stations (Li, Yan & Campana 2012; Mokhtar et al. 2012; Qadir et al. 2013). The aim of this integration option is to minimise the coal plant's output reduction by providing the thermal energy required for the CO_2 separation process with CSP and rather than from the coal fired boiler. A research/industry consortium between CSIRO and Delta Electricity is investigating this option closely and is currently testing a prototype plant in Australia (Australian Renewable Energy Agency 2013b; McGregor et al. 2013).

The use of CSP to support the gasification of coal and the subsequent synthesis gas combustion in a combined cycle power plant is being investigated as a possible means of further reducing the carbon intensity of integrated gasification combined cycle plants (Ng & Lipiński 2012; Ozturk & Dincer 2013; Zedtwitz & Steinfeld 2003). A prototype which heats coal with molten salt prior to gasification is currently being designed in the USA (National Energy Technology Laboratory 2013).

2.5.3 CSP-non-conventional fuels

CSP-non-conventional fuels refers to CSP hybrids which use various solid biomass and waste feedstocks. Such plants are a fully or predominantly renewable power generation option, depending on waste feedstock composition, and while it is a niche market at the moment, the high renewable energy prospects and secondary benefits, such as bushfire hazard reduction through biomass collection and landfill diversion, make the implementation of such facilities attractive.

2.5.3.1 Commercial references

The only commercial CSP–EfB reference in the world is the 22.5 MWe (net) Termosolar Borges plant in Spain (Protermosolar 2012). It is located further north than any other CSP project. Figure 22 shows the plant, which consists of parabolic trough collectors with thermal oil to generate saturated steam at 40 bar and two biomass boilers which subsequently superheat the CSP steam to 520 °C (Morell 2012). The other operational plant is a trigeneration demonstration facility at the University of Phitsanulok in Thailand. It is able to generate up to 50 kWe of electricity and 500 kWth for heating and cooling purposes (Solarlite CSP Technology GmbH 2014). The demonstration plant was completed in 2012 and combines parabolic troughs with direct steam generation and a biomass-fired boiler.

In 2012 the Italian utility ENEL in a consortium with a finance and a research organisation announced the construction of a 1-5 MWe CSP–EfB hybrid (ENEA-Press and Media

Relations Office 2012) but no information about the progress of this project is available. In the past several other CSP–EfB projects were developed worldwide, such as a 106.8 MWe San Joaquin plant in the USA (California Energy Comission 2008), but no other project has yet commenced construction.

Figure 22: First CSP-biomass hybrid plant in Spain, 22.5 MWe Termosolar Borges, Spain

2.5.3.2 Concepts

In the 1980s the combination of dish systems with biomass, waste and other feedstocks was suggested (McDonald 1986) but the concept was not even trialled at the prototype stage. In 2002 a 12.8 MWe CSP–EfB hybrid plant was investigated in Spain using two biomass gasifiers in combination with a solar tower providing 680 °C air to an HRSG (Romero et al. 2002). However, due to the choice of immature technologies the project did not proceed and the first CSP–EfB hybrid, the aforementioned Termosolar Borges plant in Spain, uses the conventional parabolic trough and biomass combustion technologies to minimise risk. Technology choice is important as financiers and plant operators are typically very risk averse.

A variety of more conventional CSP–EfB and CSP–EfW concepts have been investigated since then, including the use of CSP for feedwater and combustion air preheating to increase power generation but these options only allow a small 1–2% solar contribution (Kaeding 2010; Spliethoff et al. 2010). The generation of identical steam parameters from the CSP, CSP–EfB and CSP–EfW steam generators to enable joint steam turbine operation is an option to provide a significantly higher solar contribution and raise plant capacity. Studies are available which apply such concepts to the use of parabolic troughs (California Energy Comission 2008; Cot et al. 2010; Kaeding 2010; Pérez & Torres 2010; Schnatbaum 2009; Spliethoff et al. 2010), Fresnel (Nixon, Dey & Davies 2012; Rojas et al. 2010), and solar towers (Coelho et al. 2011; Peterseim et al. 2014c; Romero et al. 2002). The combination of parabolic troughs to provide identical steam parameters to EfB and EfW boilers is not ideal as the comparatively low thermal oil temperatures of less than 400 °C would limit steam temperatures to under 390°C at appropriate pressures, which in turn limits the biomass and waste feedstock conversion efficiency. Such feedstocks could be converted to ≥400 °C steam without encountering high-temperature corrosion and ash fusion-related issues inside the EfB and EfW boilers. This includes EfW plants using MSW where most units operate with steam parameters of 380–400 °C at 40 bar while newer units have higher parameters due to corrosion resistant superheater alloys (e.g. an EfW plant in Amsterdam with 440 °C and 130 bar (Gohlke 2008). To maximise biomass and waste feedstock conversion efficiency, Fresnel systems with steam temperatures up to 500 °C (Morin et al. 2011) and solar towers up to 565 °C, as in the Ivanpah plants (NREL 2014a), are better suited for hybridisation (Peterseim et al. 2013b). Dish systems can also reach such temperatures but are significantly less mature.

To improve the efficiency of EfW plants a study investigated the use of CSP to externally superheat the 380 °C steam from an EfW plant to 420 °C at 40 bar using the Fresnel technology (Kaeding 2010). The small temperature increase limits cycle efficiency gains to 0.2% but means that the plant would not require natural gas to maintain a temperature of 420 °C at times when CSP is not available as the steam turbine could continue operation at 380 °C. Some EfW plants already use the external superheater concept with natural gas rather than CSP. There are plants in operation which use superheaters directly fired by natural gas to raise the EfW steam outlet temperature from 412 °C to 522 °C at 65 bar(Andersen, Oksen & Olesen 1992) , and there are also combined cycle plants which raise the EfW steam outlet temperature from 400 °C to 510 °C at 100 bar in the HRSG (Toebes & Beker 1998). It is technically possible to realise similar steam temperature increases with CSP superheaters. However, the significant temperature rise would, even with significant TES, require the use of natural gas at times when CSP in not available.

The CSP-assisted gasification of biomass into synthesis gas is a different process to the hybridisation of CSP with biomass and waste feedstocks in mature Rankine cycle plants. CSP-assisted biomass gasification has recently been investigated in detail (Kruesi, Jovanovic & Steinfeld 2014; Kruesi et al. 2013; Lichty et al. 2010; Piatkowski et al. 2011; Saade et al. 2012; Woodruff & Weimer 2013) and since 2009 a 1 MWth test facility has been in operation in the USA (Service 2009). The benefits of a CSP–biomass-derived synthesis gas would be its use in high efficiency combined cycle plants, thermochemical energy storage, and transport fuel applications. These benefits are identical to those obtained from CSP-assisted steam reforming of natural gas, (see Section 2.5.1.2), with the difference that a CSP–biomass synthesis gas would be produced using 100% renewable energy compared to the 26% embedded solar energy involved in using CSP to reform natural gas (Stein et al. 2009).

2.5.4 CSP-geothermal

Typically, the net plant efficiency of geothermal plants is lower than that of other thermal energy plants due to the inherently low enthalpy of the geothermal resource (Zhou, Doroodchi & Moghtaderi 2013). Also some geothermal resources are located in arid regions where plants with air-cooling systems would suffer from efficiency losses during high ambient temperature periods. This means CSP is an attractive option for hybridisation with geothermal plants that face these constraints. Several concepts have been investigated for Rankine and Organic Rankine cycle plants using CSP for brine preheating, additional steam generation to maintain output during high ambient temperature periods, and steam superheating (Astolfi et al. 2011; Peterseim et al. 2014d; Rawlins & Ashcroft 2013; Zhou, Doroodchi & Moghtaderi 2013). While no commercial CSP-geothermal hybrid plants have yet been developed, studies are being carried out in the USA (Nelson & Larsen 2013) and Turkey (Kuyumcu et al. 2013) and according to parabolic trough technology provider Skyfuel a 17 MWth test plant is currently under construction at the 34 MWe Stillwater geothermal plant in the USA (Frazier 2013). The benefit of raising the efficiency of a geothermal plant is the reduction of the required number of production and injection wells which are the most expensive part of a geothermal plant, or the increase in plant capacity(Peterseim et al. 2014d).

The use of CSP to further superheat the geothermal steam is particularly promising (see Figure 23) as it has the potential to raise Rankine cycle efficiency significantly, by up to 23% in systems with parabolic troughs and by up to 38% in solar tower systems (Peterseim et al. 2014d), and it has the potential to lower the LCOE from AU$ 225/MWh to AU$ 165/MWh (Zhou, Doroodchi & Moghtaderi 2013). To minimise the use of natural gas during times without solar irradiance, substantial TES, such as 15 h, is important in order to continue CSP heat input but currently this also represents a significant cost factor. The small temperature differences of 380°C in the hot to 280°C in the cold tank render parabolic trough plants with large TES less economical than solar towers with 540°C in the hot and 280°C in the cold tank (Peterseim et al. 2014d). The hybridisation of CSP and geothermal energy sources certainly has technical and economic benefits but is has to be seen as a niche market with limited applications worldwide.

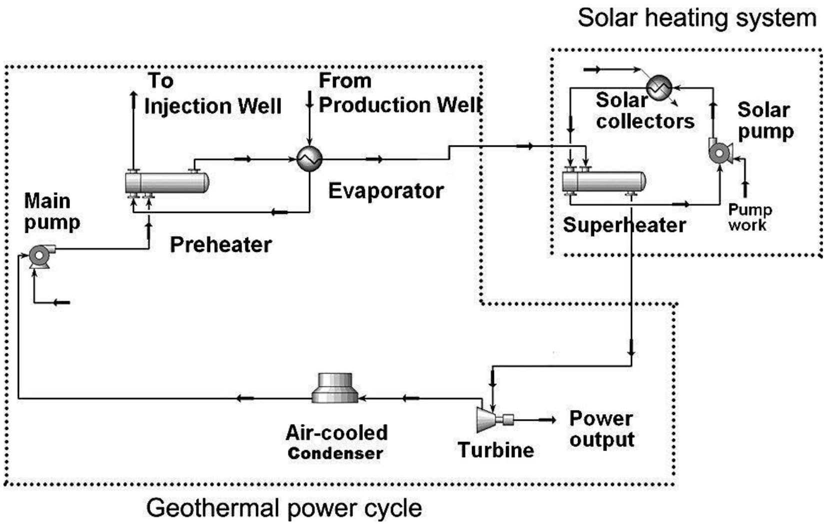

Figure 23: Schematic diagram of the hybrid solar-geothermal power plant (Zhou, Doroodchi & Moghtaderi 2013)

2.6 Introduction to transition management and transition theory

Electricity demand is expected to more than double globally between 2010 and 2050 and supplying this demand with renewable and fossil energy sources is expected to require a cumulative investment of up to US$ 26 trillion, with up to 70% of this investment being for renewable energy plants (Frei et al. 2013). This represents a significant change from the current investment pattern to a future electricity mix. The research field of transition management has been used to analyse such energy transitions, and others, for various countries across the world. First analyses came from the Netherlands where it has been used to understand, design and evaluate transition pathways to a low carbon energy system by analysing the role of public policy (Kern & Smith 2008; Rotmans, Kemp & van Asselt 2001), technical developments, and changes in rules, visions and social networks (Verbong & Geels 2007). Later similar analyses for pathways to low carbon energy systems, considering differences in local policy, infrastructure and society, were investigated for other countries, including the UK (Foxon, Hammond & Pearson 2010), Panama (Lachman 2014), and Israel (Teschner et al. 2012). Transition management can be considered as a *"a form of process management against a set of goals chosen by society"* (Kemp & Loorbach 2003, p. 12) and Rotman et al. (2001) identified five main characteristics of transition management:

- long-term thinking of at least 25 years
- thinking in more than one domain (multi-domain) with different actors (multi-actor) at different scale levels (multi-level)
- a focus on learning and a special learning philosophy (learning-by-doing and doing-by-learning)
- encouraging system innovation alongside system improvement
- keeping a large number of possible options (wide playing field).

Due to the inherent uncertainties involved when intervening in complex systems, transition management does not aim to bring about a specific transition; that is, transition management is not committed to a specific future energy system, but instead works towards a transition that "*offers collective benefits in an open, exploratory manner*" (Rotmans, Kemp & van Asselt 2001, p. 22), for example as a result of a move towards low carbon intensity electricity generation. Consequently, there is unavoidable uncertainty around future transition pathways and so continual monitoring, refinement, and adjustment is required over time. To influence transitions, a cyclical model with four not necessarily sequential components, the transition management cycle shown in Figure 24, was introduced. This model suggests the adoption of the following approach:

(1) structure the problem in question, develop a long-term sustainability vision and establish and organize the transition arena; (2) develop future images, a transition agenda and derive the necessary transition paths; (3) establish and carry out transition experiments and mobilize the resulting transition networks; (4) monitor, evaluate, and learn lessons from the transition experiments and, based on these, make adjustments in the vision, agenda, and coalitions (Loorbach 2010, p. 172).

Due to the transition context, and the actors and problems involved, every transition management process is different but the cycle is "*flexible enough for adaptation but prescriptive enough to be functional in practice*" (Loorbach 2010, p. 172).

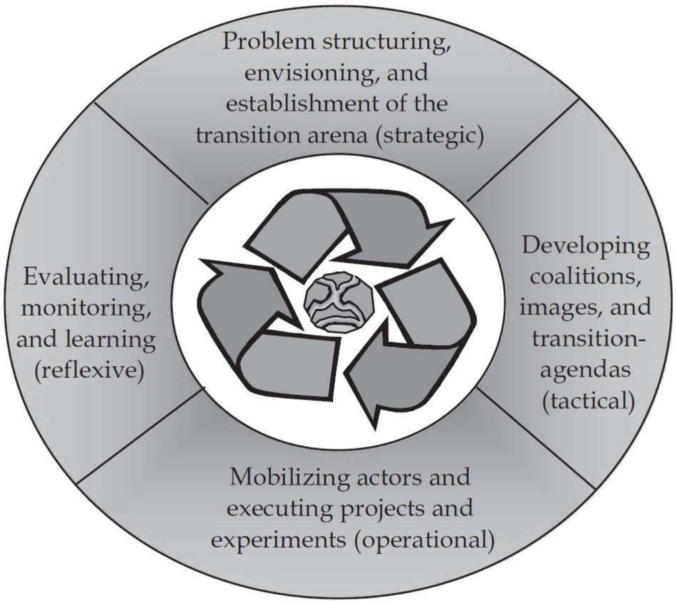

Figure 24: Transition management cycle (Loorbach 2010)

Transition management defines a transition as a *"process of change where the structural character of a society (or a complex sub-system of society) transforms*" (Rotmans, Kemp & van Asselt 2001, p. 16) and the electricity market is such a complex sub-system of society. Additionally, transitions are seen as "*a set of connected changes, which reinforce each other but take place in several different areas, such as technology, the economy, institutions, behaviour, culture, ecology and belief systems*" (Rotmans, Kemp & van Asselt 2001, p. 16). Throughout the transition process "*new products, services, business models, and organizations emerge, partly complementing and partly substituting for existing ones*" (Markard, Raven & Truffer 2012, p. 956). Enabling a transition in a certain sub-system of society requires a network of innovative actors to develop, through participatory processes, the required long-term visions, agendas and experiments which in transition management are said to form the "transition arena" (Loorbach 2010).

Traditionally, technical transitions have been used to analyse how new technologies replace existing ones but this approach is insufficient to explain the transformation of a complex sub-system of society. Socio-technical transitions extend the technical dimension by including changes in user practices and institutional structures as well as the consideration of complementary technological and non-technical innovations, such as complementary infrastructures (Markard, Raven & Truffer 2012). In light of climate change, sustainability transitions were introduced to shift socio-technical systems to more sustainable modes of production and consumption (Loorbach 2010; Markard, Raven & Truffer 2012; Schot & Geels 2008) and a key aspect of this is the role of governance to guide the process through incentives and constraints (Loorbach 2007; Smith, Stirling & Berkhout 2005).

To better understand transitions a multi-level perspective (MLP) with three levels has been introduced (see Figure 25), consisting of the socio-technical landscape, also known as the macro level; regimes, also known as meso level; and niches, also known as micro level (Geels 2002; Rip & Kemp 1998; Rotmans, Kemp & van Asselt 2001). The landscape provides an exogenous context and consists of factors that change slowly over decades, such as the natural environment, geo-economic and political developments, political culture, demography and social values. However, in some instances the landscape can also change quickly through shocks, such as wars (van Driel & Schot 2005). The landscape level exerts pressure on both the regime and niche levels. The regime level is based on dominant social, technological, economic, environmental and political structures. It provides stability and includes industry networks, techno-scientific knowledge as well as dominant practices and policies. It has various actors from industry, research and government and they often have different interests. The niche level provides the innovations that can enable transformative changes in technology, society, culture, business and governance. They are developed through small networks or individuals and relate to technologies and practices.

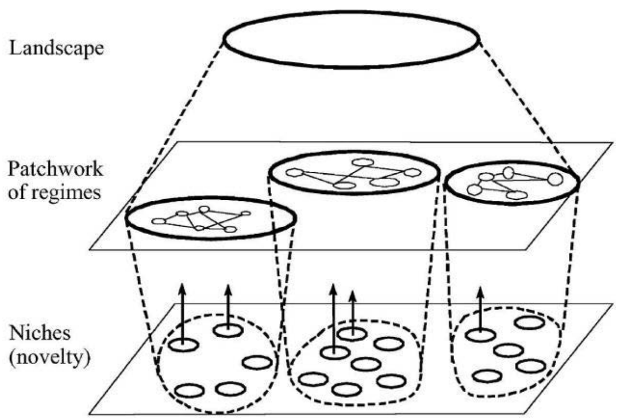

Figure 25: Multi-level perspective (Geels 2002)

Figure 25 shows that the landscape embeds the various regimes while these embed the various niches. Innovations are created "*in the context of existing regimes and landscapes with its specific problems, rules and capabilities […] on the basis of knowledge and capabilities and geared to the problems of existing regimes*" (Geels 2002, p. 1261). Innovations are initially unstable and require protection against mainstream market selection (Kemp, Schot & Hoogma 1998). According to the MLP, transitions occur through interactions between the three levels in which:

> *(a) niche-innovations build up internal momentum, through learning processes, price/performance improvements, and support from powerful groups, (b) changes at the landscape level create pressure on the regime and (c) destabilisation of the regime creates windows of opportunity for niche-innovations* (Geels & Schott 2007, p. 400).

Hence the success of an innovation is dependent on supportive developments in the regimes as well as the landscape. The concept of strategic niche management (SNM) has been introduced to describe these processes in more detail (Kemp, Schot & Hoogma 1998; Schot & Geels 2008). SNM is "*not a technology push approach [but] sustainable development [that] requires interrelated social and technical change*" (Schot & Geels 2008, p. 538) and it therefore fits well into the MLP. Being a management tool it is based on

> *the creation, development and controlled phase-out of protected spaces for the development and use of promising technologies by means of experimentation, with the aim of (1) learning about the desirability of the new technology and (2) enhancing the further development and the rate of application of the new technology* (Kemp, Schot & Hoogma 1998, p. 186).

In today's internationally connected environment many niche innovations have to be considered in a global market and therefore "*sequences of local projects may gradually add up to an emerging field (niche) at the global level*" (Schot & Geels 2008, p. 543). Figure 26 illustrates the concept which can be observed in technology learning processes where projects in one country provide valuable learning in regards to the cost, policy and acceptance of other projects elsewhere and in doing so they help to create technical trajectories.

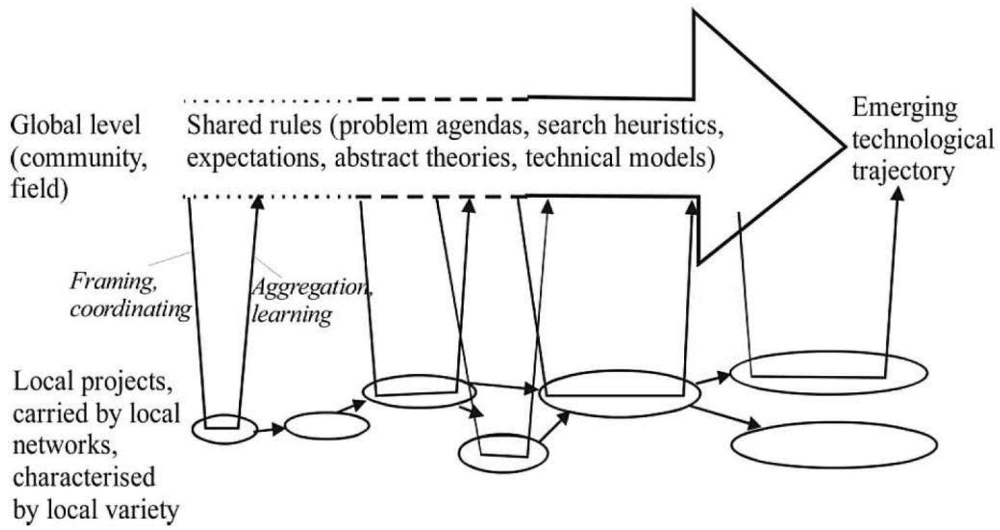

Figure 26: Emerging technical trajectory carried by local projects (Geels & Raven 2006, p. 379)

Depending on the timing and nature of interactions within the landscape, regime and niche levels, five different transition pathways have been theorised, in addition to a reproduction pathway where there is no external landscape pressure, a situation which allows the regime to reproduce itself (Geels & Schot 2007). While these pathways do not necessarily occur in their pure form, each has a recognisable internal logic:

1. Transformation pathway: Moderate landscape pressure does not allow insufficiently developed innovations to break into the regime and the regime actors respond to this by changing the development path and innovation activities. In this pathway new regimes grow out of old ones through adjustments and reorientations and most regime actors survive the transition.
2. De-alignment and re-alignment pathway: Significant landscape pressure or a specific shock increases problems in the existing regime and causes its actors to lose faith in it with the consequence that the regime de-aligns. Without sufficiently developed innovations a clear substitute is missing and various innovations emerge in the vacuum. Over time one innovation becomes dominant and the regime re-aligns.
3. Technological substitution pathway: Significant landscape pressure or a specific shock increases problems in the existing regime but this time innovations are ready to break through and replace it.
4. Reconfiguration pathway: Moderate landscape pressure allows the regime to implement some sufficiently developed symbiotic innovations to solve local problems but it remains mostly unchanged (the transformation pathway). Over

time regime actors explore further combinations, implement more innovations and thereby adjust the basic architecture of the regime.

5. Sequence of pathways: Disruptive changes in the landscape can lead to a sequence of the aforementioned pathways. Initially, regime problems are solvable with adjustments (transformation pathway) but over time problems grow and symbiotic innovations are also implemented (reconfiguration pathway). If this proves insufficient to solve the regime's problems some less developed innovations (de-alignment and re-alignment pathway) or developed innovations (substitution pathway) enter and subsequently change the regime. Other sequences with fewer pathways are possible.

Recently, another pathway has been proposed (Papachristos, Sofianos & Adamides 2013) in which at least two stable regimes with landscape and/or internal pressures do not have niche innovations for problem solving and therefore a new system emerges on the fringes of the existing ones.

Transition management is a continuously evolving field with ongoing detailed analyses of the role of government, inter- and intra-level interaction, innovation uptake and other issues. It has been used by academia and industry to understand historic transitions and to influence future transitions and it is frequently used to analyse and facilitate the world's transition to a low carbon future.

2.7 Conclusion from the literature review and research gaps

Globally, various R&D activities have been carried out on the hybridisation of CSP with renewable and fossil energy sources and in Australia several studies identified the best areas for CSP-only and fossil fuel plant retrofit options. However, a clear categorisation of CSP hybrids and a broad overview of preferred areas for CSP hybrids with coal, natural gas, biomass, waste, geothermal and wind sources is missing and Section 4.1 addresses these gaps.

Not all of the available research provides clear guidance on the technology selection process and it can be assumed that some choices are based on the selection of products from associated technology providers and extended research association with a particular technology. Technology maturity and efficiency is one of the selection criteria frequently mentioned but others such as land use, technology complexity and cost reduction potential are also relevant. A transparent comparison and evaluation of the different CSP technologies is important and multi-criteria assessments are ideal for identifying the currently preferred technology for a certain application. Multi-criteria assessments have been used in the energy sector to compare fossil fuel and renewable energy options and Section 4.3 applies the method for the first time to CSP hybrids with biomass, waste, natural gas and coal.

In Australia several studies have identified preferred areas for CSP-only plants and CSP retrofits to existing fossil fuel assets in detail, but a similar assessment for CSP–EFB and CSP–EfW hybrids is missing. Section 4.2 provides the first geospatial analysis of the ideal areas and the energy potential for such plants for Australia. Currently, similar studies are not available in any other country in the world.

A variety of research projects have investigated the hybridisation of CSP with renewable and fossil energy sources but the focus of these studies is on the combination of an individual CSP with an individual renewable or fossil fuel technology. For CSP–EfB and CSP–EfW hybrids, steam temperatures were typically limited to less than 500 °C. This is sufficient for air heating, feedwater heating, cold reheat steam. It is also sufficient for scenarios where the biomass/waste feedstock composition limits steam temperatures to under 500 °C due to high-temperature corrosion and ash fusion related issues, as experienced with wood waste, RDF and MSW. However, it is not ideal for CSP–EfB hybrids using feedstocks that allow higher steam parameters, such as wood chips, straw, and bagasse. This is a shortcoming as the identification of the best CSP hybrid concept requires a broad comparison of technologies and feedstocks, and Section 4.4 provides this comparison for CSP–EfB and CSP–EfW hybrid plants.

Worldwide and in Australia, a variety of barriers to the broad implementation of renewable energy technologies, including CSP-only plants, have been investigated but the barrier differences between CSP-only plants and hybrid plants have not been analysed yet. An analysis of the barrier differences is part of this research project and is provided in Section 4.5. Barrier rating differences between different stakeholders in energy projects are also considered.

To test the various results of the individual parts of this research project in actual situations, two case studies are provided in Section 4.6. The first case study is a hybrid power plant in Queensland involving CSP and multiple feedstocks and the second is a CSP–EfB hybrid plant in New South Wales.

This research brings together the different areas of a comprehensive technology assessment, including technology selection, techno-economic optimisation, identification of implementation barriers, resource potential and preferred regions. This method provides the first holistic view of CSP–EfB and CSP–EfW hybrid plants, and provides the basis for an analysis of their potential role in Australia's transition to a low carbon future. This analysis is presented in Section 4.7. The methodology used is also transferable to the hybridisation of CSP with other energy sources, such as natural gas or geothermal power.

3 RESEARCH DESIGN

To provide a comprehensive assessment on the potential for CSP–EfB and CSP–EfW hybrid plants in Australia this project takes a transdisciplinary approach covering technical, economic, environmental, socio-cultural and policy matters. To answer the research questions in Section 3.1 five main components and two case studies were investigated. Figure 27 outlines the components and Figure 28 the structure of this research project.

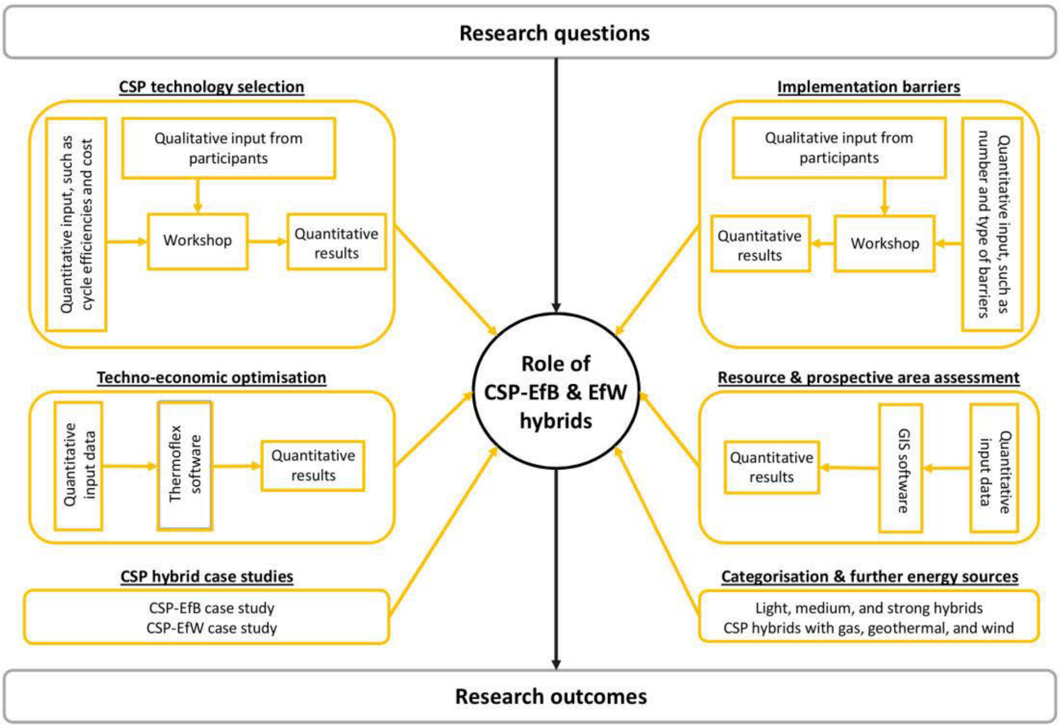

Figure 27: Research outline

The identification of suitable CSP technologies for hybridisation (see Section 4.3) was the first step as it influenced the other research components. Upon completion of the selection of the most suitable CSP technologies the other research tasks were carried out in parallel and informed the case studies, (see Figure 28). The results of the individual research tasks contributed to the analysis of the potential role of CSP–EfB and CSP–EfW hybrids in Australia's transition to a low-carbon energy future (see Section 4.7). The resource assessment and prospective area assessment (see Section 4.2) is essential for obtaining an understanding of the best sites for the construction of CSP–EfB and CSP–EfW hybrid plants while the techno-economic optimisation (see Section 4.4), is important for identifying the best technology combinations for such plants. Various barriers hinder the uptake of renewable energy technologies and an understanding the most significant ones for CSP–EfB and CSP–EfW hybrid plants (see Section 4.5), is important for future deployment. Without an understanding of the relevant barriers, even the best techno-economic power plant concept will not progress to the construction stage.

Two case studies (see Section 4.6) with different biomass and waste feedstocks were investigated to assess the feasibility of developing such CSP hybrid plants in Australia.

To broaden the applicability of this research, the hybridisation of CSP with other fuels has been examined in some detail (see Section 4.1). This examination also includes a proposal for the categorisation of CSP hybrid plants to better compare the different hybrid concepts and plants available.

Analysing these different components of the research project required the use of a variety of methods (see Section 3.2) and the identification of a suitable theoretical framework (see Section 3.3) to embed the complete work in the context of Australia's transition to a low carbon future.

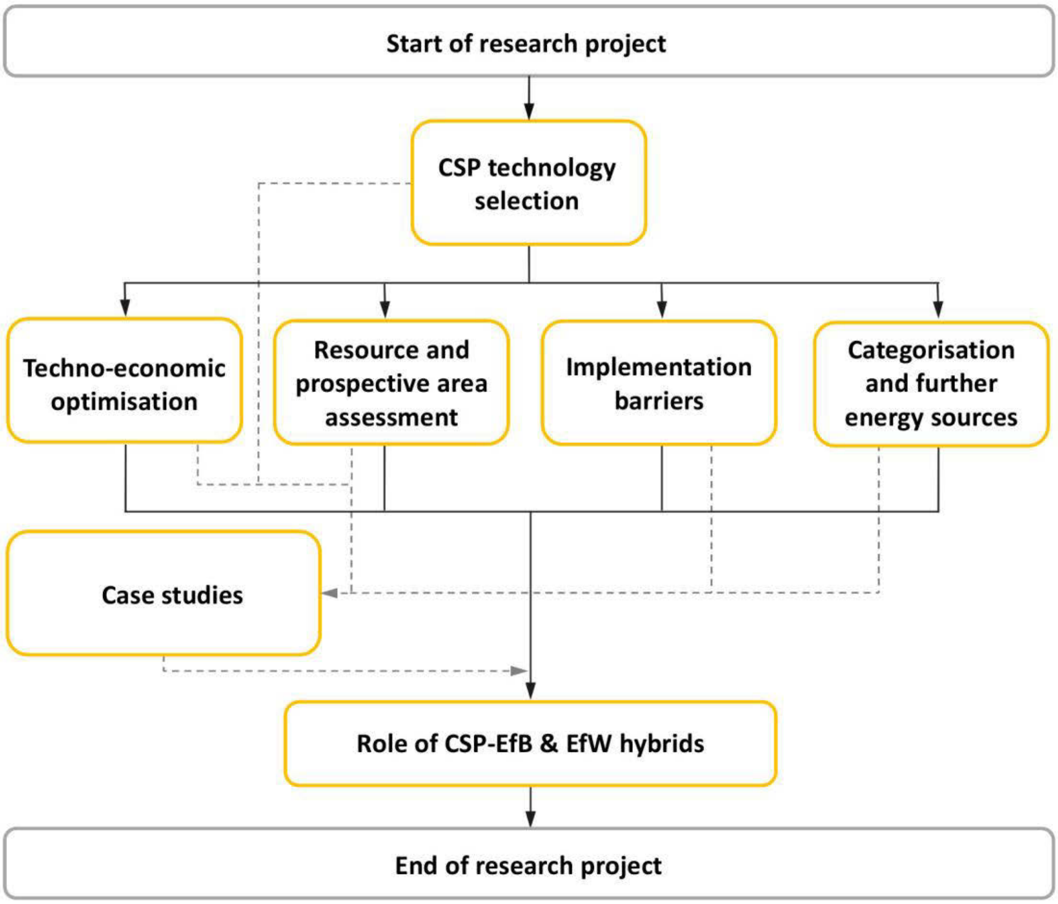

Figure 28: Research structure showing the sequence of the research components (black arrows) and the information flow (dotted arrows)

3.1 Research questions

The various areas of this project derive from the broad range of research questions it aims to answer. The main question is: What role can CSP–EfB and CSP–EfW hybrid plants play in Australia's transition to a low carbon future? This question is important because lowering the cost of implementing renewable energy is a key priority for government and industry. Section 4.7 addresses this question by investigating potential pathways for CSP-only and hybrid plants from niche technologies to being part of the mainstream energy market.

To confidently answer this overarching question, a subset of more specific technical, economic, environmental, social, and policy questions have to be answered. These are:

- What other CSP hybrid options exist with renewable sources? Section 4.1 investigates the hybridisation of CSP with geothermal and wind resources and provides maps with the preferred regions for such plants.
- Where are the ideal regions to build CSP–EfB and CSP–EfW hybrid plants in Australia? Section 4.2 identifies the preferred regions for different CSP-non-conventional fuel hybrids across Australia.
- What is the annual electricity potential of CSP–EfB and CSP–EfW hybrid plants in Australia? Section 4.2 identifies the annual electricity potential for CSP hybrids using single biomass/waste feedstocks or multiple feedstocks. The case studies in Section 4.6 provide details for two specific sites.
- What is the greenhouse gas mitigation potential of CSP–EfB and CSP–EfW hybrid plants in Australia? Section 4.2 identifies the greenhouse gas mitigation potential for CSP hybrids using single biomass/waste feedstocks or multiple feedstocks and the case studies in Section 4.6 provide details for two specific sites.
- Which CSP technologies are ideally suited for hybridisation with EfB and EfW plants? Section 4.3 investigates various CSP technologies in regards to their suitability for integration at different points in a Rankine cycle power plant.
- What are the best concepts for combining CSP with EfB and EfW systems? Section 4.4 analyses two different high solar share hybrid concepts with various CSP, EfB and EfW technology combinations.
- What are the cost differences between CSP–EfB and CSP–EfW hybrids and CSP-only plants in Australia? Section 4.4 identifies the cost differences for various CSP hybrid options and the case studies in Section 4.6 provide examples for two specific sites.
- What are the key barriers to the development of CSP–EfB and CSP–EfW hybrid plants in Australia? Section 4.5 addresses various barriers and compares them with the barriers for CSP-only plants.

3.2 Methods

In a transdisciplinary research project a variety of areas have to be investigated and a mixed methods approach was adopted which involved both quantitative and qualitative data. The methods applied include thermodynamic, economic, and geospatial modelling, multi-criteria decision-making, and workshops and interviews. This Section provides an overview of the methods used and further details are provided in the published papers reproduced in Chapter 4.

3.2.1 Workshops and interviews

To obtain a detailed understanding of a complex topic such as CSP, and to consider the various perspectives different stakeholders have in their capacities as researchers, financiers, consultants, operators, technology providers, and government representatives, it is important to directly engage with these stakeholders to avoid the generation of data that misrepresents reality. It is generally assumed that the accuracy of group judgements is greater than the accuracy of individual judgements (Sniezek & Henry 1989). Therefore two workshops were organised as part of this research project to get the judgement of a large and experienced group. The groups had 49 and 58 participants, and they discussed which CSP technologies are currently the most suitable for hybridisation (see Section 4.3), and what barriers hinder the development of CSP in Australia (see Section 4.5). Interviews were subsequently conducted with the small number of people who had other commitments on the day of the workshop.

In both workshops various pre-selected options were presented to the participants and they had the opportunity to discuss, comment and add to them before rating them from 1 to 9 (Saaty & Ozdemir 2003), with 9 being 'of extreme importance' and 1 being 'of no importance'. Questionnaires were provided for the rating process and an example for the technology selection process is provided in Section 4.3 and one for the implementation barriers in the appendix. The results of the individual ratings were aggregated to provide group and total averages, which in addition to the total ratings provide an understanding of the differences in opinion among the various stakeholders of energy projects. The process for the face-to-face and phone interviews after both workshops was identical to the workshops themselves. The various options were presented to the interviewees, they were given the opportunity to comment, add to the options, and then rate them individually.

The University of Technology Sydney's Human Research Ethics Committee reviewed and approved the design and conduct of the workshop and interview activities and Section 3.4 provides for more details about the ethics approval process.

3.2.1.1 CSP technology selection

For the CSP technology selection process, quantitative data, such as steam parameters and cycle efficiencies, and qualitative data, such as people's individual ratings, were combined using the analytical hierarchy process (see Section 3.2.3) to create the scores for the various technologies assessed. The quantitative data derived from the literature, and calculations were undertaken as part of this thesis, while the qualitative data were gathered during a workshop with 49 participants on 21 July 2011 and during three subsequent interviews. Because of the numerous quantitative data a concurrent embedded approach was taken that *"has a primary method that guides the project and a secondary database that provides a supporting role in the procedures*" (Creswell 2009, p. 214). The secondary database is qualitative and is based on the participants' judgements. Despite the qualitative data being secondary they were crucial in the identification of the best CSP technologies for hybridisation. A more detailed description of the workshop method and the results can be found in Section 4.3.

3.2.1.2 Implementation barriers

To identify the most significant CSP implementation barriers the STEEP analysis method was applied as it examines the social, technical, environmental, economic, and policy aspects of a particular problem or question (Fleisher & Bensoussan 2003). The method is widely used in academia and industry to study developments in a particular environment, such as an organisation, a state or in this case, a country.

The barrier ranking occurred during an expert workshop on 24 June 2013 with 52 professional participants and was complemented by six interviews. Unlike the CSP technology ranking process, this ranking was based purely on qualitative information from the participants' assessments of the different barriers.

A set of 25 pre-selected social, technical, environmental, economic and policy barriers was presented to the audience with some specific examples for CSP-only and hybrid plants. After the presentation the pre-selected barriers were discussed and the participants were invited to add more barriers. Seven barriers relevant to social, technical, economic and policy matters were added and the participants rated all barriers individually for CSP-only and hybrid plants. Of the questionnaires 45 were accepted for further analysis, with the remaining not being filled in properly or not returned. After the workshop all individual ratings were aggregated to identify: a) the most significant individual barriers; b) most significant barrier categories; c) a rating of the differences between participants; and d) barrier differences for CSP-only and hybrid plants. These results can be found in Section 4.5.

3.2.2 Modelling

Thermodynamic, economic, and geospatial modelling tools were used to identify the best techno-economic concepts, the best resource potential, and the most promising areas for CSP–EfB and CSP–EfW hybrid plants in Australia. To minimise the risk of the modelling being inaccurate only commercially proven software packages were used and competent partners were involved where necessary.

3.2.2.1 Techno-economic modelling

Accurate and reproducible techno-economic modelling is a key aspect of this research project and the use of a commercial software package for Rankine cycle modelling was therefore important. In this project the commercial software Thermoflex[8], versions 22 and 23, were used to identify the best currently available techno-economic CSP–EfB and CSP–EfW hybrid concepts (Section 4.4), the plant efficiencies and costs for the resource assessment (Section 4.2), and the detailed Rankine cycle designs for the case studies (Section 4.6). The software is well established, has been available since 1995, and is widely used in academia and industry to model actual natural gas, coal, nuclear, biomass, waste, geothermal and CSP Rankine cycle plants. Thermoflex is capable of providing design-point heat balances, off-design performance degradations, physical equipment sizes and cost estimates for parabolic trough, linear Fresnel and solar tower plants. Various working fluids can be used, including water-steam, molten salts, and thermal oils, and the modelling of hybrid plants is possible through more than 180 standardised component elements, including boilers, furnaces, gasifiers, feedwater heaters, flow mixers and splitters, and pumps. Other software packages have similar technical capabilities but do not provide power plant and component costs. The integrated cost estimation is unique to Thermoflex and is based on the physical design of the individual plant components as well as country-specific cost factors. To identify the best CSP–EfB and CSP–EfW concepts, robust cost estimations are important and the ability to make such estimates was, among its technical capabilities, a key reason for selecting the software for this research project.

To ensure that the Thermoflex costing is accurate for the Australian market different CSP Rankine cycle plant models were created and validated against published power plant investment data, such as € 300m for the 50 MWe Andasol II parabolic trough plant with 7.5 h of thermal storage in Spain (Solar Millennium AG 2006), AU$ 104.7m for the 44 MWe solar boost to Kogan Creek power station in Australia (CS Energy 2011), and AU$ 120m for

[8] www.thermoflow.com, accessed 04 April 2014

36 MWe EfB cogeneration plant at Mackay Sugar in Australia (Biomass Power & Thermal Magazine 2011). The Australian default cost factors in Thermoflex were adapted to match the published power plant investment amounts before changing the models to the concepts investigated in Sections 4.2, 4.4, and 4.6. Biomass boilers are not a standard Thermoflex element and had to be built from individual components, such as furnaces, superheaters, evaporators, economisers, and air heaters. The cost estimation is therefore less reliable and to improve cost accuracy prices were obtained for this equipment from the ERK Eckrohrkessel GmbH[9] in Germany, which has actual EfB and EfW experience from over 1,000 reference plants worldwide.

To incorporate future CSP cost reductions from current plant deployment, the solar field investment was lowered by 10% to reflect 2015 pricing based on a reasonable learning curve (IRENA 2012). Further details of the various Thermoflex modelling assumptions are described in the published papers reproduced in Sections 4.2, 4.4, and 4.6.

3.2.2.2 GIS modelling

Geospatial modelling is widely used in the energy sector globally to identify the best sites and resources for new fossil fuel power plants, and for plants using renewable sources including wind (Baban & Parry 2001; Hossain, Sinha & Kishore 2011; Janke 2010), biomass (Bryan, Ward & Hobbs 2008; Viana et al. 2010), and CSP (Cameron & Crompton 2008; Charabi & Gastli 2010; Clifton & Boruff 2010; Dawson & Schlyter 2012; Feeney et al. 2010; Gastli, Charabi & Zekri 2010; Parsons Brinckerhoff Australia Pty Ltd 2010; Rutovitz et al. 2013) It is also used to identify suitable sites for CSP retrofits to existing fossil fuel power plants (Meehan 2013; Turchi et al. 2011).

Various proven software packages are available on the market, and to analyse the CSP–EfB and CSP–EfW hybrid potential and the best areas for their development (see Section 4.2) the public domain software R[10] provided the capacity for the spatial biomass and waste feedstock analysis and ArcMap[11] enabled the production of maps. R is capable of classical statistical analysis, and linear and nonlinear modelling and is widely used for statistical computing. ArcMap is one of the world's leading Geographic Information Systems (GIS) and is able to analyse a range of geospatial information and produce specialised maps based on the combination of various layers. The reason for using R for the spatial biomass analysis and not ArcMap, even though it is capable of the required tasks, is R's ability to more

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[9] www.eckrohrkessel.com, accessed 04 April 2014
[10] www.r-project.org, accessed 04 April 2014
[11] www.esri.com, accessed 04 April 2014

quickly and reliably process large datasets as well as simpler programming due to a library of algorithms.

To identify the resource potential and prospective areas for CSP and CSP hybrid plants in Australia, multiple geospatial information sets such as topography, road and rail infrastructure, transmission lines, daily average DNI, biomass production, and population estimates were combined. This information was complemented with data on power plant efficiencies and costs derived from Thermoflex modelling, for the various CSP–EfB and CSP–EfW hybrid plant capacities and feedstocks. In addition several technical, economic, and environmental constraints (e.g. no plants in DNI areas <18 MJ/m^2/day, feedstock within 50 km radius around the power lines to limit transport distance and allow access to the electricity grid, and no energy recovery from native forest as well as recyclable waste materials) were applied to provide an accurate assessment of the current potential. Other relevant constraints and further details are listed in the published paper reproduced in Section 4.2.

Obtaining reliable information on the availability of different biomass resources across Australia is a complex task and therefore a collaboration with CSIRO Ecosystems Sciences and CSIRO Energy Technology was formed as they had carried out several individual geospatial analyses on biomass and CSP resource mapping. This research combined the data from the individual CSIRO studies and used this information in conjunction with further research to identify potential sites for CSP–EfB and CSP–EfW hybrid plant development. The collaboration proved successful and it provided all the skills needed for this work, such as geospatial and power plant modelling expertise, and the ability to introduce novel modelling improvements, such as the use of varying efficiencies based on power plant capacity and feedstock.

3.2.3 Multi-criteria decision-making

Multi-criteria decision-making is widely used to analyse complex problems and several models exist, ranging from the simple weighted sum model to the more complex technique for order preference by similarity to ideal solution (Triantaphyllou 2000).

The Analytical Hierarchy Process (AHP) is one multi-criteria decision-making tool that provides a comprehensive and rational framework for structuring complex decision-making problems and comparing the different alternatives. The method is widely used in academia and industry to compare fossil fuel sources with renewable energy sources, such as best electricity generation options in Jordan (Akash, Mamlook & Mohsen 1999), and more recently different CSP technologies, for example for CSP plants in India (Nixon, Dey &

Davies 2010). To compare the different CSP technologies currently available in regards to their suitability for hybridisation the AHP was used to integrate the relevant quantitative and qualitative information.

The AHP decomposes a complex problem into several sub-problems, such as risk, economics, feasibility, and environmental impact, and in doing so it provides an easy-to-understand path for multi-dimensional decision-making (Triantaphyllou 2000). The decomposition of the problem is done by identifying the main criteria and sub-criteria relevant to the problem and ranking them in a hierarchy. To compare different alternatives the AHP can use precise technical, economic and other data (quantitative information) as well as the decision-makers' personal judgments (qualitative information). In this research quantitative data were merged with the workshop participants' 1–9 criteria ratings (see Section 3.2.1) to derive a total score for each CSP technology option. The publication reproduced in Section 4.3 provides further details on the technology ranking process.

3.2.4 Case studies

Experiments and case studies are suitable tools for analysing an assumption within a research project (Yin 2009). Experiments or prototypes are not suitable for this research work as the testing of a CSP–EfB and CSP–EfW hybrid demonstration plant would require a multimillion-dollar investment and is in fact not necessary, due to advanced modelling software being available (see Section 3.2.2.1). Case studies, on the other hand, are very suitable for this research project to "*gain a better understanding of the whole by focusing on a key part*" (Gerring 2007, p. 29). One key benefit of the method is the "*depths of the analysis it offers. One may think of depth as referring to the detail, richness, completeness, wholeness, or the degree of variance in the outcome that is accounted for by an explanation. […] Case studies are thus rightly identified "holistic" analysis and with "thick" description of events*" (Gerring 2007, p. 49). The holistic analysis makes the case study method very suitable for this research as relevant aspects from various fields can be considered, e.g. technical, economic, environmental and socio-economic. Case studies are often used in various research fields, including business, political science, the humanities, and psychology, and represent a well-accepted research method (Gerring 2007).

However, a few concerns have been raised in regards to case studies in academic research, particularly in regard to the assertions that they provide little basis for scientific investigation, that they potentially lack or rigour, and that they require a significant amount of time to provide relevant details (Yin 2009). To avoid these issues the case studies in this research were designed to analyse technical, economic, environmental, socio-economic and architectural considerations. This broad analysis provided a strong basis for investigation. The risk of a lack of academic rigour was addressed by subjecting the research results to review prior to publication or prior to presentation at well regarded conferences in the CSP field (see Section 4.6). Also the feedback from various conference participants helped to bring academic rigour to the case studies. Time management is essential in every project and investigating various research aspects in a case study is indeed time consuming. Due to the author's previous project management experience, the use of commercial modelling software, and good site information, time requirements were manageable. The first case study took longer than the second as it involved the case study design, which was in large part transferable to the second case study (e.g. both case studies involved thermodynamic and economic modelling as well as greenhouse gas abatement calculations).

In this research project two case studies, shown Figure 29, were investigated. The first is a 35.5 MWe CSP-multiple feedstock hybrid plant with biomass and RDF feedstocks at the Swanbank landfill in the Ipswich local government area in Queensland (Section 4.6.1). The second is a 30 MWe CSP–EfB hybrid plant using straw at Griffith in New South Wales (Section 4.6.2). The aim of both case studies was to demonstrate that rather than being merely technically possible, CSP–EfB and CSP–EfW hybrid plants are viable business propositions for Australia and can provide sustainable energy. To achieve this technical, economic, environmental, socio-economic characteristics of the plants were analysed and comparisons provided to CSP-only plants.

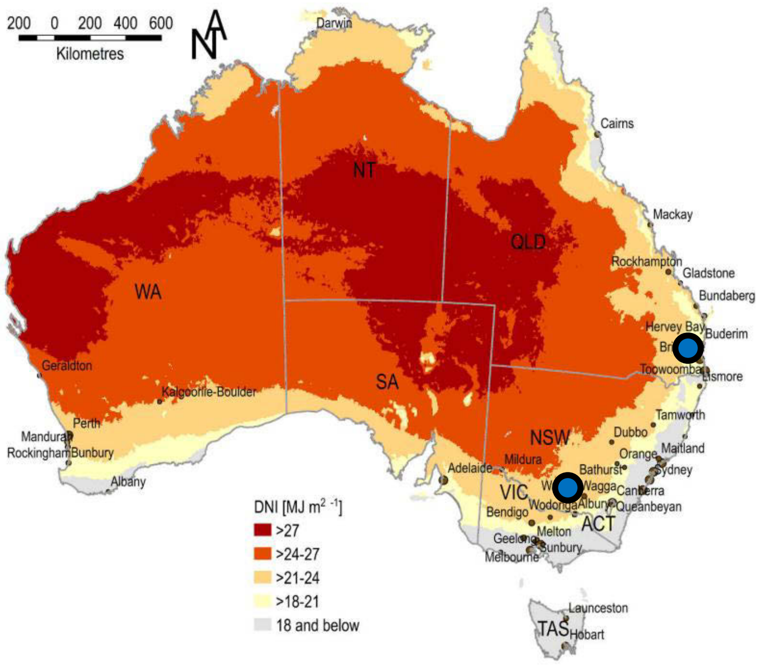

Figure 29: Case study locations in Ipswich, Queensland, and Griffith New South Wales

3.3 Theoretical framework

To analyse the integration of CSP through hybridisation into the socio-technical regime of the Australian electricity market, transition management is used as it can support the description and analysis of the various aspects of the transition process. An introduction to this concept is provided in Section 2.6. The theoretical framework for this research includes the overarching transition management framework along with two key models for analysing and managing technological transitions: the multi-level perspective (MLP) and strategic niche management (SNM). Potential transition pathways based on the MLP (Geels & Schot 2007) are also identified.

In the context of this research the four components of the transition management cycle (Loorbach 2010) are considered as follows:

1. <u>Problem structuration, long-term sustainability vision and transition arena:</u> The problem of low CSP uptake is addressed through the analysis of the various benefits CSP hybrids provide with a long-term vision in which CSP supplies a significant share of Australia's electricity by 2050. The transition arena consists of some innovative actors in the Australian electricity market who see CSP as an important technology for Australia, such as technology suppliers, utilities, researchers and the government.
2. <u>Development of future images, a transition agenda and transition pathway:</u> The future image in this research is one of a low carbon electricity market and due to CSP's unique technological characteristics, such as mature energy storage, and the excellent solar resource available in Australia, it is a valuable part of the transition agenda. The transition path considered is the reconfiguration pathway.
3. <u>Establish and carry out transition experiments and mobilise the resulting transition networks:</u> First transition experiments already exist with CSP retrofits to coal fired power plants. In most cases such symbiotic innovations will be implemented first but their potential is limited and CSP–EfB and CSP–EfW hybrid plants are among the next lower-cost niche innovations. Transition networks have already been formed with various actors having a vision of the future electricity market and the technologies needed to reach it.
4. <u>Monitor, evaluate, and learn lessons from the experiments and make adjustments in the vision, agenda, and coalitions:</u> Because there are few CSP references in Australia, monitoring, evaluation and lessons are limited and international projects are important for identifying trends. However, the local expertise is very valuable to identify country-specific factors, such as cost differences and time taken for

approval processes. With first visions built predominantly on information from international projects, particularly in regards to plant cost, local information is essential for adjusting the vision, agenda and coalitions where necessary.

Currently, CSP can be considered a niche technology that has started to enter socio-technical regimes elsewhere in the world, such as Spain and the US. While these projects provide valuable learnings for current and future projects, in accordance with Figure 26 on page 53, the technology still requires protection from mainstream market selection, such as financial support for R&D and project implementation, given that the full externality costs of fossil fuel electricity generators are not yet considered.

In the light of transitioning Australia to a low carbon future and CSP being a niche technology the MLP with an SNM approach was chosen for this research. According to SNM "*sustainable innovation journeys can be facilitated by creating technological niches, i.e. protected spaces that allow the experimentation with the co-evolution of technology, user practices, and regulatory structures*" (Schot & Geels 2008, p. 537). Additionally, SNM aims to develop particular types of innovations which are "*(1) socially desirable innovations serving long-term goals such as sustainability, (2) radical novelties that face a mismatch with regard to existing infrastructure, user practices, regulations, etc.*" (Schot & Geels 2008, p. 539). While protected spaces, which phase out over time are required to allow innovations to evolve, some controlled selection pressure is also required to allow the emergence of those innovations with the highest probability of successfully entering the regime (Schot & Geels 2008). Selection pressures include technological superiority, market preferences and lobbying associations.

Originally, the MLP was used to analyse historic transitions, such as the change from sailing ships to steam ships (Geels 2002), but has also been used more recently to design future transition pathways, such as pathways to a low carbon electricity system in the UK (Foxon, Hammond & Pearson 2010). Its three-level structure is very well suited to mapping relevant aspects of the current Australian electricity market and to analysing how CSP hybrids can be part of the transition process. SNM practices for the implementation of renewable energy systems can be observed by various governments, including Australia's, by providing financial incentives to ensure their deployment. Incentives include research grants and additional revenue streams. These practices protect niche technologies in their initial stages against mainstream selection pressures and some government programs (e.g. Germany's renewable energy law) have even incorporated decreasing revenue streams over time to allow for future cost reductions (The Federal Ministry for the Environment Nature Conservation and Nuclear Safety 2012). Consistent with Australia's current renewable energy policies such as the RET, and other incentives such as the current carbon pricing mechanism, SNM is a suitable framework for considering the implementation of CSP systems through hybridisation. This will be analysed in more detail in Section 4.7 based on five steps from Kemp et al. (1998) that enable governments to influence the transition process. These are: "*the choice of technology, the selection of an experiment, the set-up of the experiment, scaling up the experiment and the breakdown of protection by means of policy*" (Kemp, Schot & Hoogma 1998, p. 186).

Early MLP and particularly SNM work was critiqued for a focus on a bottom-up process where niche expansions lead to regime shifts, as shown in Figure 25 on page 51. However, recent work (Geels 2011; Schot & Geels 2008) addresses this and other critiques by acknowledging that in addition to the importance of niche innovations "*they can only diffuse more widely if they link up with ongoing processes at regime and landscape levels*" (Schot & Geels 2008, p. 539). Hence it is acknowledged that both landscape and regime changes and pressures are essential to successfully transform a socio-technical regime. The extended MLP (Geels & Schot 2007) shown in Figure 30 includes the different regime actors, indicates the interactions between the three levels in more detail, and shows that with time a dominant niche innovation evolves due to the selection processes. The relevant Australian landscape, together with regime and niche characteristics and pressures for CSP–EfB and CSP–EfW hybrid plants, are discussed in this context in Section 4.7.

According to Geels and Schot (2007), if they are to lead to a transition CSP–EfB and CSP–EfW hybrid plants have to meet two criteria. These criteria are related to: 1) the nature of the interactions between landscape, regime and niche; and 2) the timing of the innovation's development. The nature of the interaction refers to niche innovations and landscape developments reinforcing the regime, which stabilises it and discentivises transitions, or to niche innovations and landscape developments disrupting the regime, which applies pressure and incentivises transition. The timing refers to the ability of an innovation to take advantage of landscape and regime pressures. This ability is dependent of the degree of maturity of an innovation. Technological maturity is debatable and researchers, technology suppliers, plant operators and financiers will all have different perspectives. Geels & Schot (2007) introduced four criteria which they argue need to be met before an innovation can be considered to be mature: *"(a) learning processes have stabilised in a dominant design, (b) powerful actors have joined the support network, (c) price/ performance improvements have occurred and there are strong expectations of further improvements and (d) the innovation is used in market niches, which cumulatively* *amount to more than 5% market share"* (Geels & Schot (2007), p. 405). CSP–EfB and CSP–EfW hybrids are analysed based on these criteria in Section 4.7.

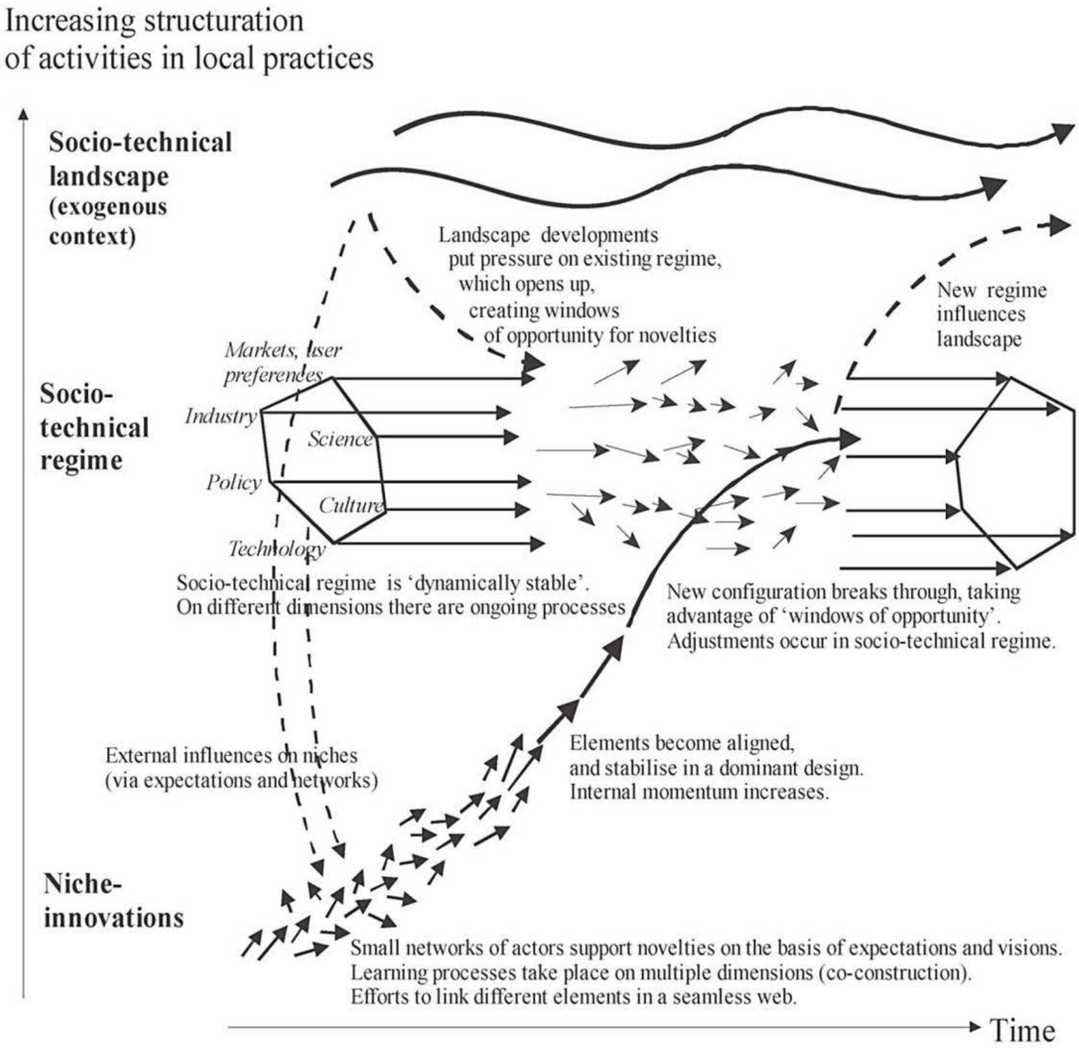

Figure 30: Multi-level perspective on transitions (Geels & Schot 2007, p. 401)

However, to analyse the prospective CSP implementation pathway in more detail the reconfiguration pathway is chosen from the various transition pathways mentioned in Section 2.6. Figure 31 shows this pathway, as proposed by Geels & Schott (2007). This pathway is based on moderate landscape pressure on the regime leading to the implementation of some sufficiently developed symbiotic innovations to solve local problems. The regime remains mostly unchanged, as in the transformation pathway, however over time regime actors explore further combinations, implement more innovations and in doing so they adjust the basic architecture of the regime.

This pathway is the most suitable for this research as through hybridisation CSP can provide symbiotic innovations to the current Australian electricity regime, such as CSP retrofits to existing power stations. With regime actors such as utilities and financiers exploring further

CSP options, new CSP–EfB and CSP–EfW hybrid plants and also CSP-natural gas hybrid plants could enter the regime and over time adjust its basic architecture to allow the broad uptake of CSP technologies in the future.

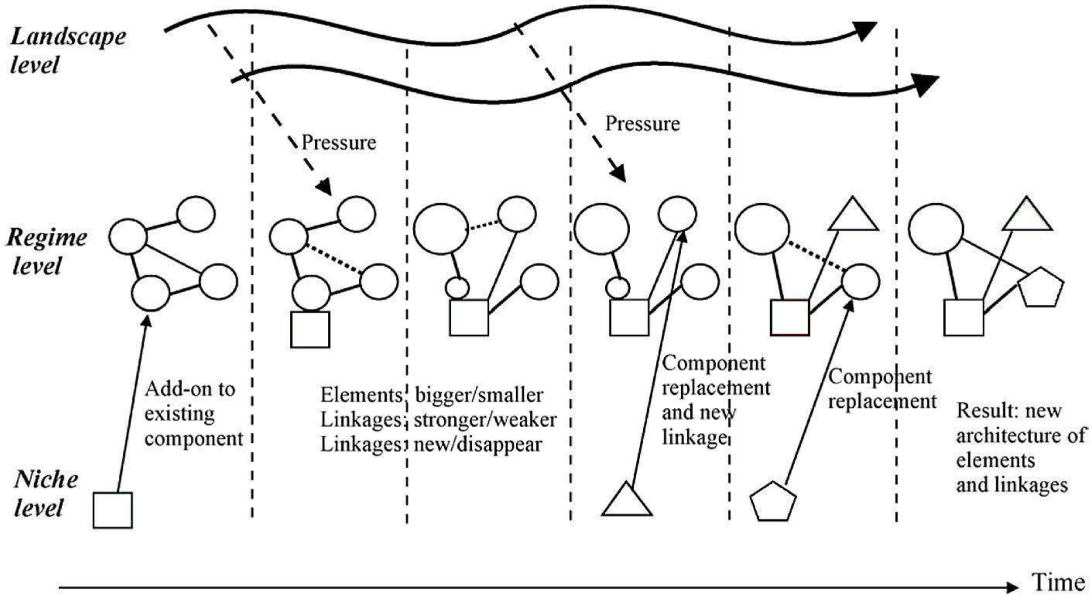

Figure 31: Reconfiguration pathway (Geels & Schot 2007)

Transition management also uses additional research theories and methods, such as systems thinking, action research and case study method (Loorbach 2007; Rotmans & Loorbach 2008) and requires qualitative input. According to Rotmans, Kemp & van Asselt (2001) qualitative measures are essential to achieve real transition. Stakeholder engagement, as emphasised by transition management, can also be found in action research where "*the relationship between researcher and researched (the other-the object) is seen as an interactive and linguistic relationship, characterised by joint action, joint involvement and shared responsibility*" (Ottosson 2003, p. 90). Action research tools have been used in transition management (Loorbach 2007).

To include the various aspects of CSP–EfB and CSP–EfW hybrid plants, this research project includes quantitative technical, economic and environmental data as well as qualitative input from various stakeholders. A form of action research can be found in this research since strong stakeholder engagement was an important feature throughout various parts of project. These stakeholders included workshop participants, CSIRO Ecosystems Sciences, CSIRO Energy Technology and Thiess Services Pty. Ltd.

3.4 Research ethics

To obtain feedback on CSP technologies and barriers from active stakeholders in Australia's energy market, this research project engaged with them through workshops and interviews. At the Univerity of Technology, Sydney this engagement required ethics approval from the Research Ethics Committee to:

- minimise risk and harm for research participants and researchers
- protect the confidentiality and privacy of the participants
- ensure that pre-existing relationships do not affect the research
- guarantee that data collection, analysis, storage, and disposal are in accordance with UTS guidelines.

These issues were addressed in a comprehensive application for ethics approval which was lodged on 17 May and granted on 5 July 2011. The approval letter is provided in the appendix. Measures to mitigate the aforementioned risks included consent forms from the participants, no publication of individual but only aggregated results, only references to stakeholder groups and not individuals, secure data storage and destruction of hard copies after five years.

4 RESULTS AND DISCUSSION

This chapter provides the analyses for: the CSP hybrid categorisation, further CSP hybrid configurations, CSP technology selection, CSP–EfB and CSP–EfW resources, techno-economic optimisation, implementation barriers, the case studies, and the role CSP hybrids can play in Australia's transition to a low carbon future. It is structured differently to a conventional thesis as most of the individual results and discussions have already been published and these publications are incorporated in the various Sections of this Chapter. Therefore the Sections also include a description of the methods that is more detailed than the outline provided in Section 3.2 and the answers to most research questions are provided in the publications.

4.1 CSP hybrid categories and energy source combinations

The following publication introduces a categorisation of CSP hybrid plants based on the degree of interconnection of the plant components. It also answers the research question about other CSP renewable energy hybrid options and addresses the hybridisation of CSP with natural gas and coal. The publication aims to demonstrate that in addition to CSP–EfB and CSP–EfW hybrid plants, other hybrid configurations are possible in areas of Australia where multiple energy sources are available in the same location.

It should be highlighted that the discussion about the CSP boost at the Liddell coal fired power station in Section 4.1 in the paper refers to the recently commissioned 9.3 MWth solar field (Novatec Solar GmbH 2012b) and not the initial demonstration plant (Mills, Lièvre & Morrison 2003). The initial demonstration plant was built in 2004 and in fact very valuable as it demonstrated the Fresnel technology for the first time at an industrial scale and provided important testing for further design improvements. Since then significantly larger CSP plants, incorporating the learnings from the demonstration project, have been built and are under construction by successors of the original company Solar Heat and Power Pty. Ltd., including the 8 MWth CSP boost to the Liddell power plant in Australia (AREVA Solar 2012b), the 5 MWe Kimberlina plant in the USA (NREL 2014b), the 44 MWe equivalent Kogan Creek Solar Boost in Australia (CS Energy 2011), and the 2x 125 MWe Reliance power plant in India (AREVA Solar 2012a). The demonstration plant was therefore an important milestone in CSP technology development and deployment.

The discussion a CSP-natural gas hybrid plants in Section 4.2 of the publication does not consider "greenwashing" issues as the CSP-coal section does. However, CSP systems in new and existing natural gas fired plants should also have a significant CSP share and need to be evaluated based on their net environmental benefits or possible technology advancements.

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Concentrating solar power hybrid plants – Enabling cost effective synergies

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A B S T R A C T

This paper categorises different concentrating solar power (CSP) hybrid options into light, medium and strong hybrids and discusses the combination of CSP with coal, natural gas, biomass and waste materials, geothermal, and wind. The degree of hybridisation depends on the interconnection of the plant components. Light hybrids create only limited synergies, such as the joint use of a substation, and their cost reduction potential is therefore limited, while strong hybrids share major plant components, such as steam turbine and condenser, and can better match their energy output with electricity pricing.

The hybridisation options for CSP with different energy sources are plentiful ranging from feedwater heating, reheat steam, live steam to steam superheating with some options better suited for a specific energy source combination than others. The synergies created in hybrid plants can lead to cost reductions of 50%, better energy dispatchability as well as revenue maximisation.

Several CSP hybrid studies exist for coal, natural gas and biomass but these are often investigating a specific hybrid concept. This paper considers several options at a higher level and also includes geothermal and wind which is novel.

While the paper focuses on Australia the approach taken and concepts discussed are transferable to other countries.

1. Introduction

Despite an excellent solar resource and some state and federal programs for concentrating solar power (CSP) there is no commercial standalone CSP plant in operation in Australia yet. Some proposals secured significant state/federal funding, such as AU$464m for 250 MWe SolarDawn and AU$60m for 40 MWe SolarOasis projects, but neither was able to secure the remaining funding and had its support subsequently withdrawn [1,2]. Policy uncertainty and CSP's comparatively high investment compared to other renewable energy sources, such as wind and biomass, in a traditionally low wholesale cost electricity market are key reasons for the poor success rate.

Different to standalone CSP plants hybrid plants are being built in Australia with one plant already operational at Liddell, New South Wales [3], and another one under construction at Kogan Creek, Queensland [4]. Several studies investigate hybrids with gas [5,6] and even biomass [7] but none have yet been built.

CSP hybrids are well established worldwide, predominantly with natural gas [8–10] but also biomass [11], and provide lower cost benefits through the joint use of plant equipment, such as steam turbine, condenser and feedwater equipment, and better energy dispatchability as the host plant can provide electricity during times when CSP is not operating. Both aspects could help the Australian CSP industry to start grow their market share, ramping up manufacturing capabilities as well as gaining relevant project implementation experience. The wind and PV industries realised learning curve cost reductions of 15–20% when doubling cumulative deployment [12] and the CSP business could benefit similarly. At the same time plant operators and financiers would become more familiar with the variety of CSP technologies and their specific benefits. Another benefit of hybrid projects is the smaller investment, which reduces financial risk, and would particularly help newly developed CSP technologies to prove their capabilities. Due to a minimum CSP plant efficiency scale of 10–100 MWe for standalone systems such projects incur a higher financial risk over kWe scale PV systems. However, CSP add-on references exist at sizes of only 9 MWth [3].

Typically, standalone CSP plants require a direct normal irradiance (DNI) levels >20 MJ/m^2/day but the lower specific investment

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of hybrid systems allows the implementation in lower DNI areas which are often closer to load centres. The first CSP–biomass plant in Spain is located in 18 MJ/m^2/day DNI area [13] and other studies consider regions with even lower DNI levels of 17 MJ/m^2/day [14].

Natural gas, biomass and waste materials as well as geothermal are obvious energy sources to hybridise with CSP as such plants can share Rankine cycle equipment but also the integration of wind has benefits in terms of joint use of plant infrastructure and energy dispatchability.

While CSP hybrids are being discussed broadly in academia and industry with several studies on different integration options for CSP with a specific fuel, this paper categorises hybrid plants and discusses not only one energy source but several.

2. Methods

The technical and economic information provided in this paper derive from the literature and own modelling work using Thermoflex version 23.0. The software is widely used in academia and industry to model actual gas, biomass, waste, coal, geothermal and CSP plants.

The maps provided are based on publically available information which is combined using a commercial imaging software. References to the different energy sources, DNI, and transmission infrastructure are provided in each relevant section. Sites with a DNI >18 MJ/m^2/day are considered suitable for CSP hybrids as commercial plants already operate in such DNI areas [13].

3. Hybrid categories

With a variety of possible CSP hybridisation options it is sensible to categorize these to better assess the degree of dependence between CSP and the other power generation component. The following three categories are suggested to do this.

3.1. Light hybrid synergies

Light CSP hybrids only share minimal plant infrastructure and the operation of the different assets does not depend on each other, such as CSP and a wind farm jointly using the switchyard and substation. This results in only minimal cost savings unless both plants can share the cost for building new transmission infrastructure, which would be a major benefit as transmission lines are capital intensive.

Despite the minimal interaction of both generation assets one plant could use certain equipment from the other to enhance its energy dispatchability/limit curtailment if this equipment is not being used at its maximum capacity at this point of time. One example would be a wind farm topping up the thermal storage of a CSP plant in winter to store some of its electricity via electric heaters in molten salt for dispatch at higher electricity prices at a different time of the day.

3.2. Medium hybrid synergies

Medium CSP hybrids are physically connected with each other and share major equipment, such as the steam turbine or condenser. However, the CSP component requires the operation of the typically much larger host plant while the host plant can operate without the CSP component. Currently, this is the dominant form of CSP hybrids where the CSP plant provides feedwater heating [3], cold reheat steam [4], or a saturated/superheated steam boost [8,9,15]. These concepts exist for CSP with coal and natural gas.

Due to the joint use of capital intensive plant infrastructure cost reductions can be significant but the solar share in these concepts is typically below 10% of the installed plant capacity.

3.3. Strong hybrid synergies

Strong CSP hybrid plants are physically connected with each other, share major equipment and have a significantly higher solar share, >30%, compared to medium CSP hybrids. CSP plants using another fuel to further superheat its steam fall in this category, such as 100 MWe SHAMS One using natural gas [16]and 22.5 MWe Termosolar Borges using biomass [13]. Alternatively the CSP component can be used to raise the steam parameters of low temperature renewable energy sources, such as geothermal plants [17]. The external superheating concept increases plant efficiency and hence lowers cost. Strong hybrids also include plants where CSP and the other energy source provide similar quantities of high temperature/pressure steam parameters to the joint turbine, e.g. 30 MWe CSP hybrid study for Griffith, Australia [18].

Strong hybrids can reduce specific plant investment significantly while enabling solar shares of 30–90%.

4. Hybridisation options

Several hybridisation options exist to integrate CSP into the Rankine cycle of another power plant. They include feedwater heating, reheat steam and high pressure/temperature live steam, see Fig. 1, and the most suitable CSP technologies for these options with biomass, waste, natural gas and coal have been assessed recently [19]. All three options have been implemented in reference plants worldwide, e.g. Liddell [3] and Kogan Creek in Australia [4], Martin Next Generation in the USA [8] and Archimede in Italy [15].

Using CSP to externally superheat low temperature steam is another option which has not been realised yet, but the concept is discussed in more detail in Section 4.4.

4.1. CSP–coal

Several studies investigate the different CSP integration options with utility scale coal fired power stations [20–22] and from a technical and commercial perspective they are all sensible with positive results in terms of CSP cost reductions and conversion efficiencies, e.g. specific investment of AU$2.4/MWe for Kogan Creek solar boost [4]. However, when proposing CSP retrofits to coal fired power plants other criteria, such as age and remaining lifetime of the power station, have to be considered carefully to assess the real greenhouse gas abatement potential and avoid “greenwashing”. With coal fired power stations having a design lifetime of circa 40 years and CSP plants requiring up to 20 years to amortise, coal plants older than 10–15 years should not be retrofitted as extending its operation only for a short period of time can offset the avoided greenhouse gas emissions from the CSP add-on due to the typically small solar contribution, well below 10% of the plant capacity.

The recently commissioned 9.3 MWth CSP feedwater boost at the 2 GW Liddell power station is an interesting example as it reduces greenhouse gas emissions by approximately 5000 t/a [3], which is equivalent to only 2.8 h of full-load operation of the coal station with its carbon intensity of 892 kg/MWh or 0.064% of the stations 2011–12 annual emissions from 8764 GWh of electricity generated [23]. There is no doubt modern power stations exist, typically supercritical, where a solar boost makes economic and environmental sense, such as 44 MWe solar boost to 750 MWe Kogan Creek power station [4], as these latest generation plants, Kogan Creek was commissioned in 2007, are most likely to operate for the next 25–30 years. However, other projects might add a small renewable energy component to an older unit to justify operation beyond the initial design lifetime. The recent CSP feedwater booster at the Liddell power station could be such a case as

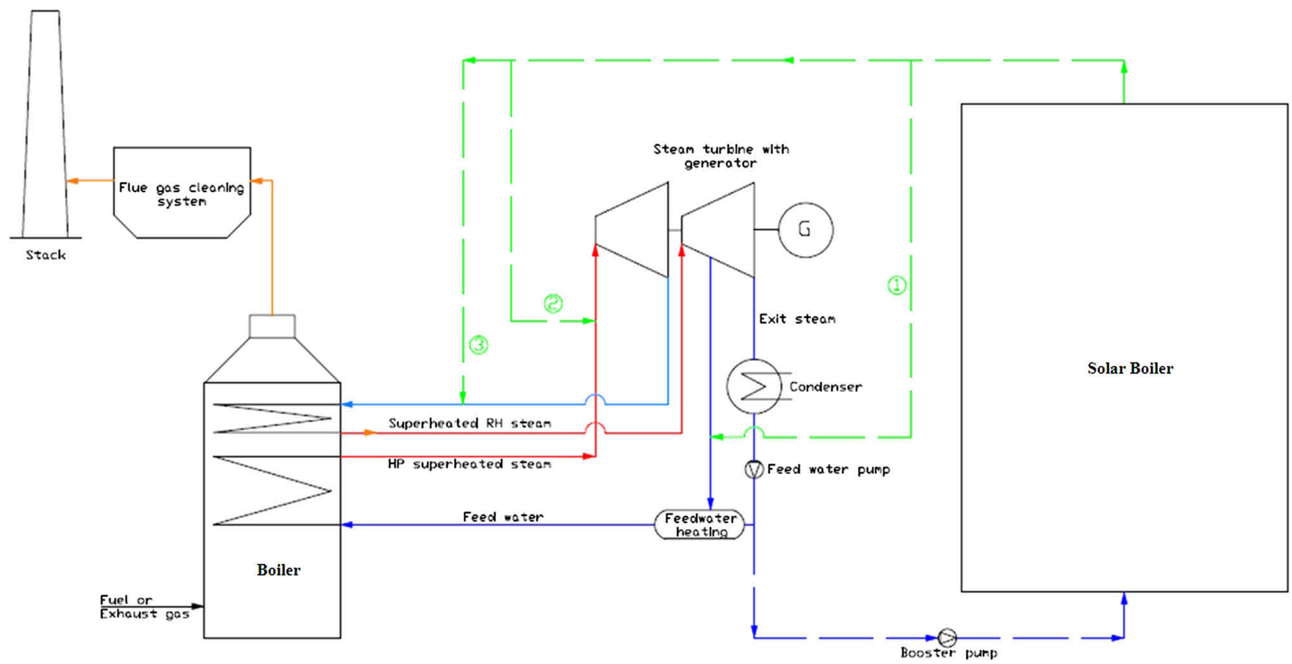

Fig. 1. Simplified schematic of CSP integration options into host plants. (1) Feedwater heating; (2) high pressure steam; and (3) cold reheat line [19].

the coal units were commissioned in 1971 [23] and the CSP add-on is very small.

4.2. CSP–natural gas

Currently, most CSP hybrids operate as integrated solar combined cycle (ISCC) plants in combination with combined cycle gas turbine (CCGT) plants and references exist in the US [8], Morocco [10] and Egypt [9]. These plants use the CSP component to provide additional saturated steam to the high pressure drum of the heat recovery steam generator where the high temperature gas turbine exhaust superheats the combined steam quantity. Feedwater heating would be another option but has not been realised yet.

The CSP component could also provide similar steam parameter as the HRSG to the high pressure steam turbine and the first plant is in Priolo Gargallo, Sicily [15]. This 5 MWe reference uses parabolic trough with molten salt to provide up to 538 °C steam to the 760 MWe CCGT's steam turbine. Different to ISCC's with parabolic troughs an ISCC solar tower concept has been investigated but no reference plants exist yet [6].

Almost all CSP plants have a natural gas fired start-/back-up heater but these heaters are not designed to provide full-plant capacity or continuous operation but rather for plant start-up, generation stabilisation and emergency operation. However, a full capacity gas fired boiler in parallel to the CSP component is a technical option but would result in a low natural gas conversion efficiency compared to a CCGT plant. It is therefore not a recommended option.

For new plants the combination of CSP and natural gas has the potential to reduce LCOE from US$243/MWh to US$175/MWh [24]. This 38% cost reduction is significant and could fast-track CSP deployment in low price wholesale electricity markets such as Australia. Retrofits of CSP to existing open or combined cycle gas turbine plants can realise even lower LCOE, e.g. US$150/MWh [25]. Despite the use of a fossil fuel and depending on the ISCC concept the solar contribution can be >50% [24] while the use of natural gas to further superheat the CSP steam, such as in the SHAMS One plant, has the potential to achieve solar contributions >80% [16].

The potential for ISCC plants in Australia is high as several natural gas fired power stations already operate/are proposed in suitable DNI areas, see Fig. 2. Particularly promising is the Pilbara region in Western Australia and the Mount Isa region in Queensland where gas prices and direct normal irradiance (DNI) levels are higher than elsewhere. However, several mining sites outside these regions qualify as well. ISCC plants do not exist yet but are investigated at different stages, e.g. 30 MWe Collinsville project [5] and 228 MWe ISCC in Port Hedland [6].

4.3. CSP–biomass and waste materials

Some early efforts to combine CSP with biomass or waste materials were discussed briefly in the 1980s with dish systems [29]. However, for several reasons no plants were built and it took another 25 years before construction of the first commercial CSP–biomass hybrid plant commenced near Lleida, ca. 150 km west of Barcelona, Spain [30]. The 22.5 MWe Termosolar Borges plant came online in late 2012 [11], is located further north than any other CSP project in Spain and uses the mature parabolic trough technology with thermal oil [31].

Several other studies investigated the hybridisation of parabolic trough plants with biomass [14,32–34] but no other project has yet commenced construction. Alternatively, Fresnel has been investigated for hybridisation with biomass and waste materials [35–37]. The benefit of using Fresnel would be steam temperatures of up to 500 °C [38] and subsequent higher conversion efficiencies. However, no reference plants exist yet either. For CSP–biomass hybrid plants with steam parameters, >500 °C and >100 bar, solar towers are best suited with direct steam systems preferred for plants without thermal storage and molten salt systems for plants with thermal storage. Solar towers with volumetric air receivers have been investigated as well [39] but it is likely that securing finance for such a project is more complicated due to the limited reference situation.

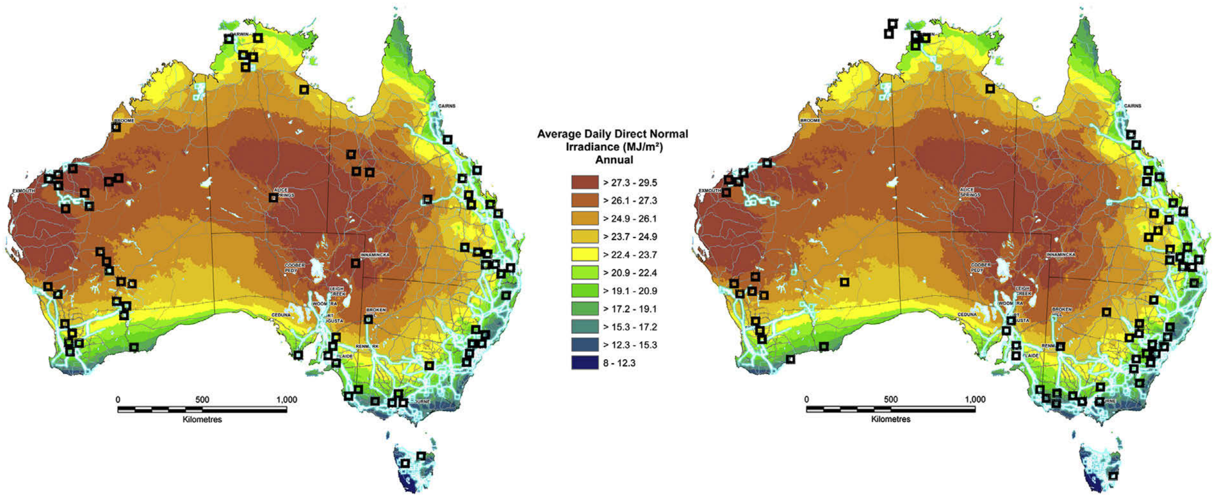

Fig. 2. Overlay of DNI [26] with operating natural gas plants (left) and proposed natural gas plants (right) [27] and transmission infrastructure [28].

While most studies consider the generation of identical steam parameters from biomass and CSP some publications investigate the use of CSP for air and feedwater heating as well as external steam superheating from an energy from waste plant [40]. However, none of the concepts considers CSP steam temperatures >430 °C which limits the conversion efficiency.

A recent 30 MWe CSP–biomass hybrid study in Australia shows a specific investment of AU$4.2m/MWe for the biomass and AU$7mMWe for CSP component, a combined specific investment of AU$5.6m/MWe. A standalone CSP plant with the same annual generation (26 MWe solar tower with 15 h thermal storage) would require AU$11.2/MWe including the network connection [18]. This equals a significant 50% cost reduction and other CSP–biomass studies indicate similarly significant cost reductions through hybridisation [14]. This difference is likely to decrease with CSP prices expected to decrease in the future but will not reach the cost competitiveness of a CSP–biomass hybrid due the inherently higher labour requirements for the manufacturing and installation of CSP systems compared to a biomass power station.

In Australia several agriculture regions exist with sufficiently high DNI levels for CSP systems, see Fig. 3. Several potential areas exist in Queensland, New South Wales, Victoria, South and Western Australia that have a similar or better DNI than the Lleida region in Spain. Also CSP–waste hybrid plants could be considered as waste materials downstream a recycling process are low cost and cause other environmental problems, such as leachate or fugitive emissions in landfills. To obtain some economy-of-scale benefits a minimum of 5 MWe is recommended, which would require a population of ≥4080 people assuming the 2011 Australian average electricity consumption of 10.7 MWh per capita [41]. Several such cities exist, such as Mildura in Victoria or Griffith in New South Wales.

4.4. CSP–geothermal

Currently, both standalone geothermal and CSP are considered higher cost renewable energy sources, compared to wind or biomass, with high capital requirements for components such as solar field and production/injection wells. The combination of both resources provides not only the potential to share plant equipment, such as steam turbine or condenser, but also significant efficiency and investment improvements.

The net plant efficiency of geothermal plants is 8–10% comparatively low due to the low steam enthalpy from Australian resources. Raising the cycle efficiency is desirable and would reduce the number of capital intensive production and injection wells, the most expensive part of a geothermal plant or increase plant capacity with the same brine flow. Several CSP integration options

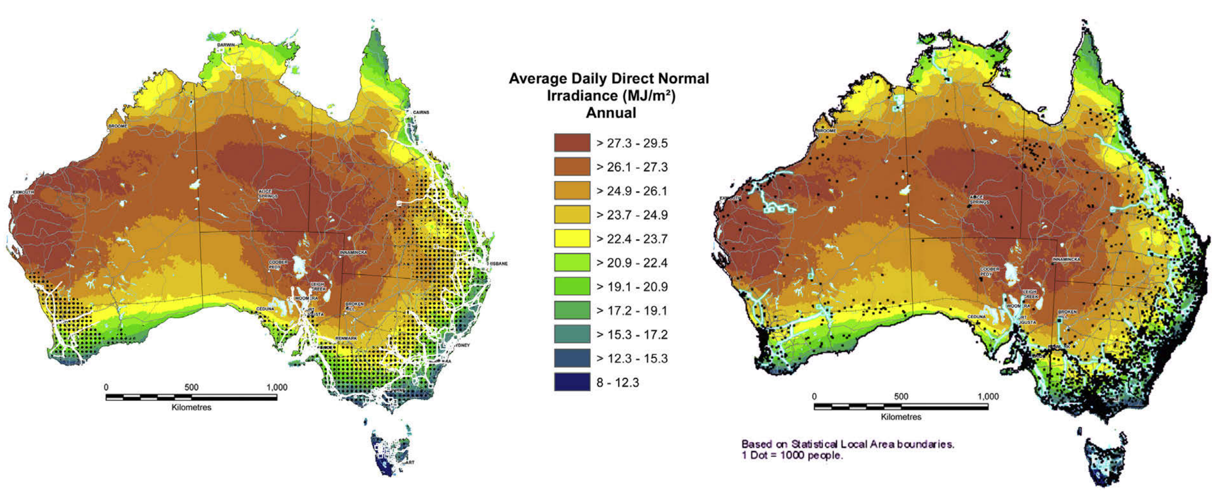

Fig. 3. Overlay of DNI with suitable biomass land use areas (left) [42] and population distribution (right) [43] with transmission infrastructure.

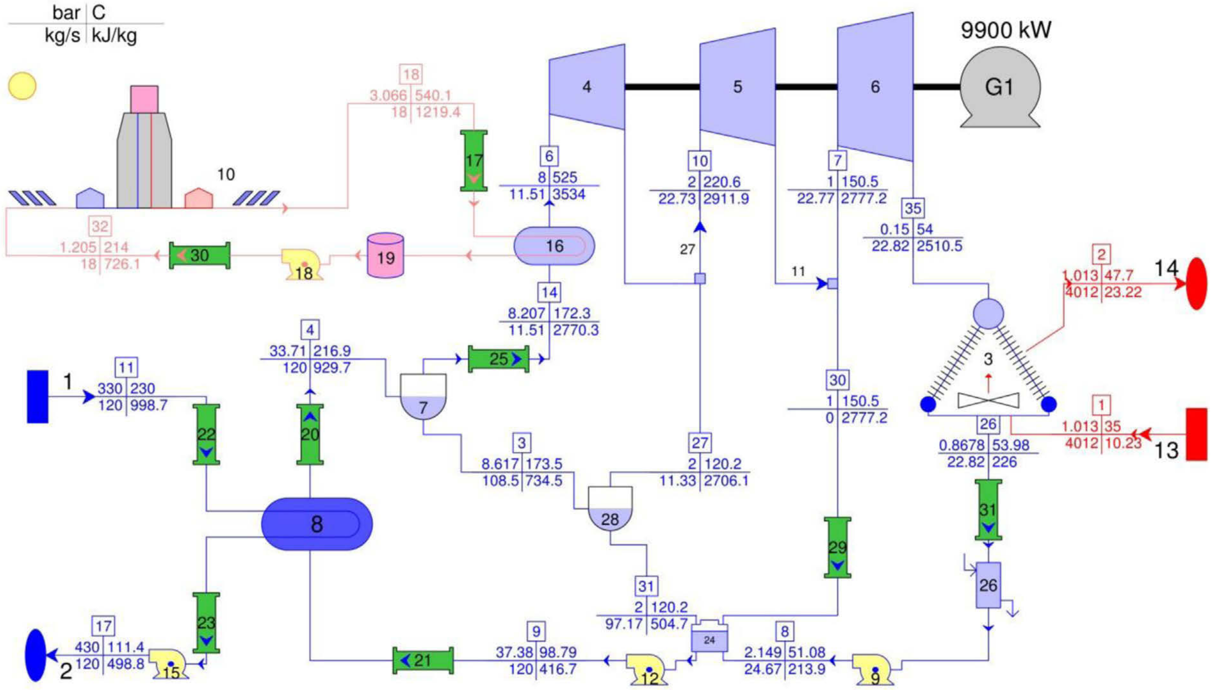

Fig. 4. Process diagram of a geothermal plant with CSP post-flashing steam superheating.

exist ranging from feedwater heating, the generation of identical steam parameters and CSP steam superheating. To limit changes to current geothermal plant concepts and to maximize cycle efficiency CSP is best used to further superheat the "low" temperature geothermal steam, typically between 150 and 200 °C at 6–10 bar, to 380 °C with a parabolic trough and to 525 °C with a molten salt solar tower system. Fig. 4 explains the geothermal–solar tower hybrid concept with the production and injection wells (1–2), the brine-water/steam heat exchanger (8), flash tanks (7, 28), solar tower with thermal storage (10), CSP steam superheater (16), steam turbine (4–6), generator (G1), condenser (3), feedwater heating system (24), as well as brine (15), molten salt (18) and feedwater pumps (9, 12). Steam superheating requires only around 20% of the total energy input which minimises the CSP component and its cost. Significant thermal storage, such as 15 h, increases the solar share and reduces the use of natural gas for external superheating during the night/CSP system maintenance. Typically, natural gas and other fossil fuels are expensive in remote locations but an additional external superheater system is required for back-up purposes.

Based on the brine flow in Fig. 4 the net plant capacity of a geothermal only plant would be 6.3 MWe with a net cycle efficiency of 10.2% and a specific investment of AU$20.5m/MWe. The external steam superheating with a parabolic trough system would result in 8.4 MWe, 12.5% net cycle efficiency, and AU$22.1m/MWe while the solar tower option would yield 9.9 MWe, 14.1% net cycle efficiency, and AU$16.8m/MWe. The integration of a parabolic trough system can provide technical benefits but the high thermal storage cost, due to low molten salt temperature differences of 380 °C in hot and 280 °C in cold tank, actually increases the specific investment. Smaller thermal storage capacities would lower the specific investment but increase the use of natural gas for steam superheating. The higher temperature difference of the thermal storage system in a solar tower (540 °Cin hot and 280 °C in cold tank) lowers storage cost and makes the geothermal–solar tower hybrid economically more viable and also reaches the best technical performance.

Complementary to CSP steam superheating the generation of additional steam through the CSP component could be considered to compensate the geothermal output reduction during the day due to higher ambient temperatures. An ambient temperature increase from 20 °C to 45 °C can, depending on condenser design, reduce plant output by around 20%.

Australia has high potential for CSP–geothermal hybrid plants with the best resources overlapping in Queensland, New South Wales and South Australia, see Fig. 5. Particularly, promising are Longreach in Queensland and Leigh Creek in South Australia as transmission infrastructure is already available.

4.5. CSP–wind

The combination of CSP with wind, currently one of the lowest cost renewable energy sources, has been investigated for Texas, US, and results show that the combination of CSP with wind farms provides some benefits in terms of load matching [45]. With wind generation typically being lower during the day than at night the addition of CSP provides further daytime and evening power to match the demand profile. Fig. 6 shows the generation profile for wind only and different CSP–wind configurations.

In addition to the co-location of CSP and wind both forms of generation could be more integrated by adding electric resistance heaters into the CSP plant's thermal storage system to store wind energy during low price and dispatch during high price periods. Electric heaters are almost 100% efficient and a mature technology with thousands of references in various industries. Typically, electricity prices are lower at night and some of the wind energy could be used to fully charge the thermal storage for dispatch during the morning electricity peak. During winter the CSP plants can rarely charge their thermal storage to 100%, due to less daily solar irradiance, which makes it more complicated to dispatch electricity for all of the attractive evening period unless the plant has a very large thermal storage system. With the electric heater option wind could fully charge the thermal storage and provide electricity during this attractive period.

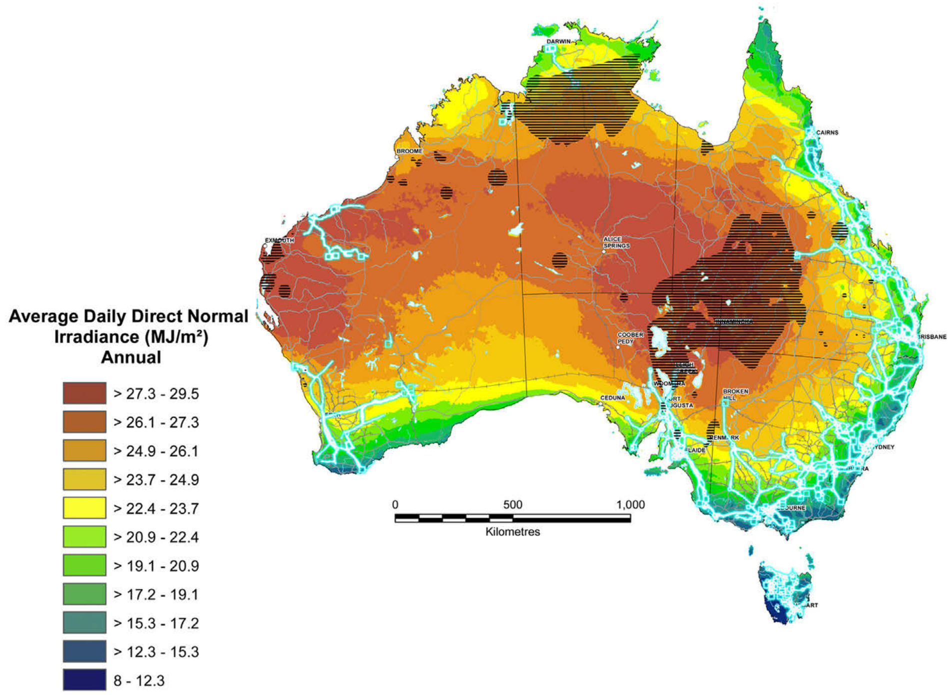

Fig. 5. Overlay of geothermal resources >200 °C [44] in DNI areas >19.1 MJ/m^2/day with transmission infrastructure.

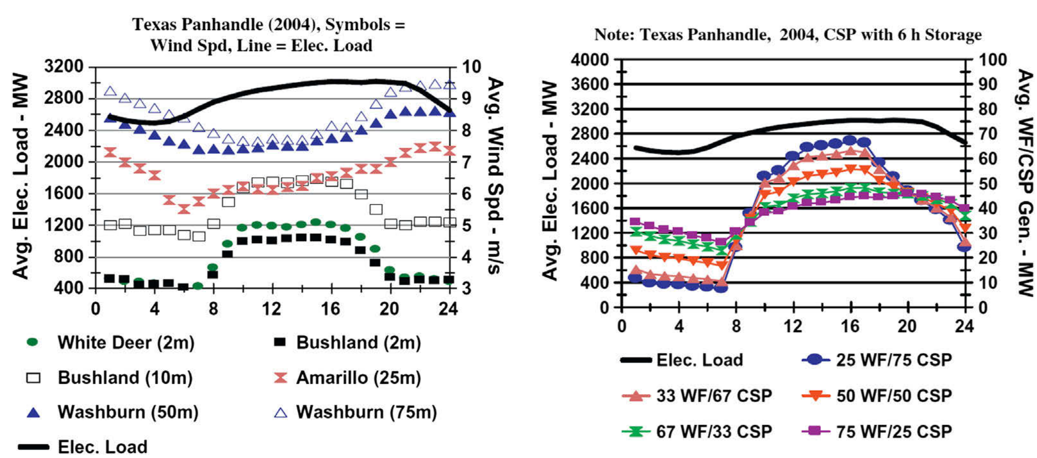

Fig. 6. Diurnal mismatch of wind speed with utility electrical loading as height increases (left) and annual utility loading compared to different ratios of wind farm to CSP rated generation in 2004 [45].

However, assuming a 99% electric heater efficiency and 39% CSP plant cycle efficiency the electricity price difference between charging and discharging the thermal storage would have to be >260%. This is a significant price difference but such events occur frequently, for example dispatch interval prices of AU$40–60/MWh between 0 and 6 AM and AU$110–180/MWh between 5 and 10 PM [46], and could improve the economic viability of CSP and wind generation. Additionally, areas with network congestion, such as South Australia [47], could reduce curtailment by temporarily storing wind generation.

To minimize renewable energy losses and investment the electric heater capacity should not exceed 5–10% of the CSP plant capacity. The aim should not be to use wind to fully charge but only top-up the CSP thermal storage to cover high electricity price periods better and increase financial viability.

Some wind farms and CSP plants are already co-located but not integrated, such as the Dólarwind farm close to the Andasol I–III CSP plants in Spain, and several sites in South and Western Australia have potential for CSP–wind hybrids, see Fig. 7. Particularly promising are locations north of Port Augusta (South Australia) and between Perth and Geraldton (Western Australia) as the DNI is high and transmission structure available.

5. Conclusions

Several CSP hybrid options with different energy sources are discussed in this paper and results show that depending on plant concept and energy source combination, the cost of hybrids can be up to 50% lower than for standalone CSP plants. Also CSP hybrids can lower the cost of other renewable energy sources, such as geothermal, by

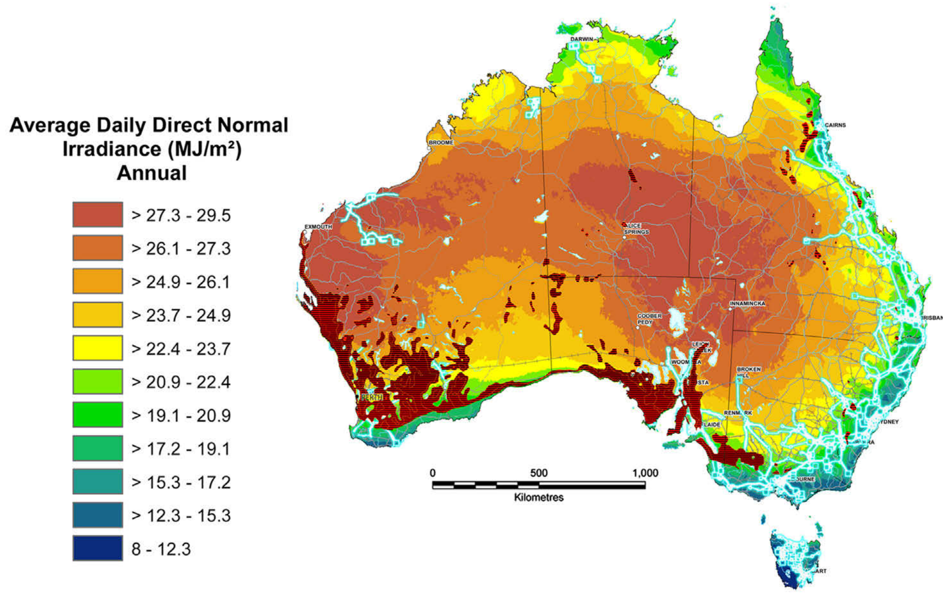

Fig. 7. Overlay of wind resources >7 m/s [48] in suitable DNI areas >19.1 MJ/m^2/day with transmission infrastructure.

significantly increasing cycle efficiency. These benefits paired with the potential to realise small CSP installations, rather than several hundred million or even billion dollar projects, allow financiers and operators to understand the different CSP technologies better and finance larger hybrid and standalone systems in the future.

Categorising CSP hybrids into light, medium and strong synergy systems enables a clear understanding of the different options and degrees of interconnection. While energy sources sharing Rankine cycle components with CSP, such as natural gas and biomass, have an inherently higher potential for synergies, and therefore cost reductions, even the combination with wind provide benefits in terms of revenue optimisation by matching electricity output with market prices.

Considering that CSP is currently a high cost renewable energy source its hybridisation with other fuels, ideally renewables, can fast-track the implementation of CSP systems in Australia, allow the growth of a local industry, test different CSP technologies and therewith help transition Australia's electricity mix from coal domination to a mix of renewable energy sources.

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4.2 CSP-non-conventional fuel potential and plant area identification in Australia

The following publication investigates the annual electricity generation potential and ideal areas for CSP–EfB and CSP–EfW hybrid plants in Australia. It answers three research questions:

- Where are the ideal regions to build CSP–EfB and CSP–EfW hybrid plants in Australia?
- What is the annual electricity potential of CSP–EfB and CSP–EfW hybrid plants in Australia?
- What is the greenhouse gas mitigation potential of CSP–EfB and CSP–EfW hybrid plants in Australia?

The geospatial modelling for this work was carried out in cooperation with Dr Deborah O'Connell and Dr Alexander Herr from CSIRO Ecosystems Sciences, and Sarah Miller from CSIRO Energy Technology. Based on the analyses requested by the author, the available geospatial information on biomass, waste and solar resources was combined by Dr Alexander Herr with the power plant cost and efficiencies, provided by the author. Using several jointly developed constraints, the collected information was used to produce maps showing the most promising regions for CSP–EfB and CSP–EfW hybrid plants in Australia. The author thanks Dr Deborah O'Connell, Sarah Miller and Dr Alexander Herr for their cooperation and support during this analysis.

In addition to the detailed CSP–EfB and CSP–EfW resource assessment in this publication, a higher level analysis to identify potential CSP–EfB hybrid plant areas worldwide is provided in the publication in Section 4.4.2.

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Concentrating solar power/alternative fuel hybrid plants: Annual electricity potential and ideal areas in Australia

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ABSTRACT

Australia's extensive solar resource is underexploited especially in the CSP (concentrating solar power) arena because of the high investment and lack of stable investment incentives. CSP hybrid plants provide an option to improve returns from CSP installations because of lower specific investment. This paper investigates the generation potential and most prospective regions for 5–60 MWe CSP hybrids using forestry residues, bagasse, stubble, wood waste and refuse derived fuels in locations with a direct normal irradiance >18 MJ/m^2/day. Different plant efficiencies are used to identify the overall electricity potential for single and multiple feedstocks systems. The EfB (energy from biomass) or EfW (energy from waste) components of the hybrid plants considered are assumed to allow base load operation with the CSP components providing additional capacity during the day.

The total CSP-EfB & EfW hybrid potential in Australia, within 50 km of existing transmission and distribution infrastructure, is 7000 MWe which would require an investment of AU$ 39.5b to annually generate 33.5 TWh. This is equivalent to 12.8% of all electricity generated in 2008–2009 or 74% of Australia's 2020 renewable energy target. The CO_2 abatement potential of CSP-EfB & EfW hybrids is up to 27 Mt or 4.8% of all 2009–10 CO_2 emissions.

1. Introduction

Australia has one of the best solar resources in the world, however the historically low electricity prices compared with most other OECD (Organisation for Economic Co-operation and Development) countries has constrained the broader implementation of CSP (concentrating solar power) and other renewable energy plants. There are currently no standalone CSP plants in Australia and the two significant projects that were offered state/federal funding, being AU$ 464m for 250 MWe SolarDawn and AU$ 60m for 40 MWe SolarOasis projects, had their offers withdrawn in 2012 and 2013 as neither project was able to secure the remaining funding [1,2]. While solid biomass and waste feedstocks are available for power generation [3], few plants operate at commercial scale, total installed capacity of 170 MWe [4], and only one new 36 MWe industrial scale facility in Mackay, Queensland [5], commenced operation in the last four years.

The comparatively high cost of CSP and continuous/significant cost reductions of PV (photovoltaic) systems has in recent times put pressure on CSP. The decision to switch the first 500 MWe phase Blythe (USA) parabolic trough project to PV is the most prominent example of the competition with PV so far and it is likely that the second 500 MWe phase will be PV too [6]. In order to remain competitive, the CSP industry has to further demonstrate the grid value and other benefits of CSP arising from energy dispatchability as well as reduce plant costs. High renewable energy scenarios modelling in Australia identified CSP as a key technology to provide grid stability [7].

The hybridisation of CSP with forestry residues, bagasse, stubble, wood waste and RDF (refuse derived fuels) is one promising option to realise these two objectives and is endorsed globally [8] and in Australia [9]. Such hybridisation, not only with biomass or

Abbreviations: CSP, concentrating solar power; PV, photovoltaic; EfB, energy from biomass; EfW, energy from waste; DNI, direct normal irradiance; AU$, Australian dollar (AU$/US$ = 0.96).

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waste, can provide distributed renewable/low-emission dispatchable power, capacity factors of up to 91%, CSP uptake in DNI (direct normal irradiance) areas lower than the usual >20 MJ/m^2/day, and investment reductions up to 28% [10] through the joint use of equipment and avoidance of currently capital intensive thermal storage.

Currently, several CSP hybrid plants operate as solar add-ons to coal and gas plants worldwide. Compared to the deployment of standalone CSP plants around the world, Australia deployed only CSP hybrids. In particular, the 9.3 MWth CSP-coal at Liddell is in operation [11], the 44 MWe CSP-coal at Kogan Creek is under construction [12], and new hybrids under investigation are a 30 MWe CSP-natural gas hybrid at Collinsville [13] and 35.5 MWe CSP-biomass hybrid in Ipswich [14].

In contrast to fossil fuels, forestry residues, bagasse, stubble, and wood waste are renewable resources. Only the non-renewable RDF fraction is fossil derived but consists largely of non-recyclable materials that would otherwise go to landfill. Including avoided fugitive landfill gas emissions EfW and EfB systems can be a greenhouse gas negative form of power generation [15]. Late in 2012, the first commercial scale CSP-EfB hybrid plant, 22.5 MWe Termosolar Borges using parabolic trough technology, commenced operation near Barcelona, Spain [16], which is significantly higher latitude and therefore has a lower solar resource than all other CSP plants in Spain [17]. The Termosolar Borges plant is built in an agricultural area with a DNI of 18 MJ/m^2/day and is using forest and agricultural residues [18].

Similar or equivalent regions, in terms of combined biomass production and DNI >18 MJ/m^2/day, exist in Australia. Agriculture and forestry in Australia produce significant quantities of biomass and some of it could be used as feedstocks for electricity generation as well as biofuels [3,19,20]. Investigations show that due to Australia's high carbon intensity electricity mix significantly greater greenhouse gas mitigation can be realised by using biomass for electricity generation, 30 Mt CO_2 equivalent, rather than biofuels, 9 Mt CO_2 equivalent [3]. The high solar irradiation in many Australian agriculture/horticulture areas offers the unique possibility to use both energy sources in designated plants. Non-recyclable and renewable waste materials, such as RDF, can be used in CSP hybrid plants, would increase the overall feedstock potential, divert waste from landfill, and reduce fugitive landfill emissions.

Different studies used GIS (geospatial) modelling to identify suitable regions and sites for standalone CSP power plants [21–26] and CSP retrofits to existing fossil fuel plants [27] in Australia but the objective of this paper is to identify regions in Australia which may be suitable to site CSP-biomass hybrid plants with different power generation capacities. It provides a broad scale assessment of Australia's CSP-EfB & EfW hybrid potential and forms a basis for project developers and researcher to investigate specific sites within the most prospective regions identified. No such work has been undertaken to date in Australia, and the information is a critical pre-commercial step required to underpin future commercial feasibility assessments of CSP plant locations.

2. Methods

This assessment applies thermal analysis and GIS modelling to identify the electricity potential and the most prospective regions for CSP-EfB & EfW hybrid plants. The modelling includes specific technical, environmental and economic constraints as well as performance differences in regards to power plant feedstock and capacity.

2.1. GIS modelling

Globally geospatial/GIS modelling is widely used in the energy sector to identify the best sites and resources for new renewable and fossil power plants, including wind [28–30], biomass [31,32], standalone CSP [21–26,33,34] as well as CSP retrofits to existing fossil fuel plants [27,35]. Various proven software packages are available and for this paper the public domain software R (www.r-project.org) provided the capacity for the spatial biomass analysis and ArcMap (www.esri.com) enabled the map production. The daily average DNI (direct normal irradiance) for Australia was derived from 1995 to 2011 gridded hourly solar exposure data from the Bureau of Meteorology Australia [36]. Road and rail infrastructure stem from topology 250K data [37], and population estimates are based on the 2006 census data [38]. Biomass production and potential availability is based on a recent Australian assessment of biomass for bioenergy [3] and stubble [39,40], while RDF data derived from several publications [41–43] combined with population estimates. The CSP and biomass resource data/maps in Section 3 derive from the combination of this information.

Transmission lines were identified with information from Geoscience Australia [44], Australian Energy Market Operator Australia [45], the Energy in Australia 2011 report [46] and Western Power [47]. The exact GIS locations of transmission lines in Australia are not publicly available and therefore had to be approximated. This assessment considers transmission lines ≥66 kV as they can technically absorb the output of 5–60 MWe CSP hybrid plants. A 50 km buffer around transmission lines was included in the GIS model as this is a viable transport distance for biomass [3].

To identify plant capacities, annual generation, and investment shown in Section 3, local biomass quantities were combined with the power plant modelling results (Tables 1–4), considering environmental, technical and economic constraints (2.3). Multiplying the locally available feedstocks with conversion efficiencies, capacity factors and costs lead to final investment requirements, e.g.

- stubble availability in a particular area of 42,500 t/a * conversion efficiency of 0.94 MWhe/t (Table 4) = 40,000 MWhe/a biomass generation
- 40,000 MWhe/a/8000 h biomass capacity factor (constraint in 2.3) = 5 MWe biomass capacity
- biomass capacity equals CSP capacity = 10 MWe hybrid plant capacity
- 1577 h/a CSP capacity factor (constraint in 2.3) * 5 MWe CSP capacity = 7885 MWhe/a CSP generation
- 7885 MWhe/a CSP + 40,000 MWhe/a biomass = 47,885 MWhe/a total generation, and
- 10 MWe hybrid capacity * AU$ 7.2m/MWe (Table 1) = AU$ 72m investment.

The Australia wide potential for CSP-biomass hybrids is identified by combining all areas that met the constraints. Additionally,

Table 1
Specific investment data for different CSP hybrid plants sizes in AU$m/MWe for the >21–24 MJ/m^2/day DNI category.

Feedstock	10 MWe	20 MWe	30 MWe	40 MWe	50 MWe	60 MWe
Forestry residues + CSP	7.0	5.6	4.8	4.4	4.3	4.2
Bagasse + CSP	7.1	5.7	4.9	4.5	4.4	4.3
Urban wood waste + CSP	7.5	6.0	5.2	4.7	4.6	4.5
Refuse Derived Fuels + CSP	7.6	6.1	5.3	4.8	4.7	4.6
Stubble + CSP	7.2	5.8	5.0	4.4	4.4	4.3

Table 2
Calorific values, boiler efficiency, fuel conversion efficiency, and maximum recommended steam temperatures.

Feedstock	Fuel CV (dry), MJ/kg	Boiler efficiency, %	Fuel conversion efficiency, MWh_{th}/t fuel	Max. Steam temperature, °C
Forestry residues	19.0	90.7	4.79	540
Bagasse	17.7	90.5	4.45	540
Urban wood waste	17.7	89.0	4.38	450
Refuse derived fuels	18.6	85.9	4.44	430
Stubble	15.7	89.5	3.90	540

the CSP-EfB & EfW hybrid electricity potential is modelled for single and multiple-feedstock plants.

2.2. Power plant efficiency and cost modelling

Thermoflex version 23.0 (www.thermoflow.com) was used to model the different power plant efficiencies and investment. The software is used in academia and industry to model actual parabolic trough, Fresnel and solar tower plants.

The plant sizes considered range from 5 to 60 MWe to realise economy-of-scale benefits and limit feedstock transport distances and emissions. The power plant efficiencies were modelled individually for all feedstock and plant size categories (Table 3) considering different steam parameters, economy-of-scale efficiency changes and feedwater heating arrangements. Plants smaller than 20 MWe are modelled without steam reheating, while larger units include a single reheat. Process models for clean biomass feedstocks, such as forestry residues, only include a baghouse filter while contaminated materials, such as RDF, have additional flue gas scrubbing equipment. All models are based on 25 °C ambient temperature, the use of air cooled condensers, a solar multiple of 1.4 (solar field is oversized by this multiplier to achieve full-load at below design point conditions) and avoidance of flue gas condensation. Thermal storage is not modelled in detail as the EfB/EfW component ensures lower cost power generation, albeit some part-load efficiency losses, than thermal storage at night and during extended cloud coverage.

Both the CSP and the EfB/EfW steam generators are expected to provide superheated steam at 400–540 °C, depending on fuel quality, to individually meet 50% of the plants installed capacity (Figs. 1a and 2). This plant configuration is chosen to a) have a significant CSP share in the hybrid plant, b) allow CSP to capitalise on typically higher electricity prices during the day (Fig. 1b), c) provide additional generation capacity during higher daytime demand, and d) ensure efficient part-load operation at night. Without CSP, the plant's cycle efficiency with only biomass, at a part-load of 50%, would only be 10% lower than the hybrid at full load. The plant cycle efficiency reduction at part-load is not as great as first expected because at night only the steam turbine operates in part-load, while the biomass boiler is still operating at full capacity and its maximum design efficiency. Also condenser performance increases at night. Operating the steam turbine <50% part-load would lead to significantly higher cycle efficiency reductions. This hybrid concept has already been investigated for two sites in Australia and is at this point in time commercially more attractive than a CSP standalone plant in these locations [48,49].

In comparison to other assessments on the bioelectricity potential, such as Farine et al. (2011) [3], this assessment uses different boiler and power plant efficiencies for the individual feedstock and plant capacities (Tables 2 and 3), resulting in varying conversion efficiencies for the individual fuels (Table 4). The feedstock strongly affects the maximum steam parameters recommended for the EfB/EfW plant (Table 2) as some substances, such as chlorine or potassium, cause high-temperature corrosion and ash fusion related problems on the superheater section of the boiler. Because of the feedstocks different composition it also determines the boiler's maximum efficiency to avoid dew-point corrosion on the boiler tubes.

Single and multiple-feedstock plants have been considered in this assessment. Single-feedstock plants have higher individual cycle efficiencies as the plant can be purpose designed for one fuel. Power plant cycle efficiency increases with capacity (Table 3), which benefits multiple-feedstock plants in any location. In general feedstock availability limits plant size, so multiple feedstock sources enable larger plant capacity. These multiple-feedstock plants capitalise on economy-of-scale benefits, even though they need to be designed for the lowest feedstock quality in the mix.

The Thermoflex cost database is used for the different power plant components to identify the specific plant investment (Table 1). With biomass boilers not being a standard Thermoflex component, industry prices were obtained for this equipment to optimise investment accuracy [50]. Prices consider economy-of-scale differences, different flue gas cleaning options, steam reheating >20 MWe and different DNI levels. Confirmation of the costing has been demonstrated by modelling the 36 MWe EfB project at Mackay Sugar in Queensland and the 44 MWe Solar Boost at Kogan Creek in Queensland. The investment for Mackay Sugar is AU$ 120m [5] and Solar Boost AU$ 104.7m [12]. Modelling both projects resulted in a 5% higher investment (4.7% Mackay Sugar and 5.3% Kogan Creek) which is acceptable as not all project data are known. Additionally, both plants are retrofit projects which typically have lower cost through the use of existing infrastructure.

The investment for CSP hybrid plants with an 18% capacity factor (percentage of actual power production of a plant compared to its power output at continuous full-load operation) depends on the quality of the DNI resource and this assessment uses the three different DNI categories shown in Fig. 3. The specific investment shown in Table 1 is the basis for the >21–24 MJ/m^2/day category, while the 18–21 MJ/m^2/day DNI category requires a 10.3% higher investment. The investment decreases by 4% in the >24 MJ/m^2/day area. The reason for the investment differences is the fixed CSP capacity factor, which results in smaller solar fields in higher DNI areas and larger solar field in lower DNI areas. With the solar field

Table 3
Biomass hybrid plant net cycle efficiencies for varying plant capacities and feedstocks.

Feedstock	5 MWe	10 MWe	15 MWe	20 MWe	25 MWe	30 MWe
Forestry residues + CSP	24.4%	27.2%	29.1%	33.4%	33.8%	34.1%
Bagasse + CSP	24.2%	26.8%	28.6%	31.9%	33.0%	33.5%
Urban wood waste + CSP	22.9%	26.0%	27.2%	30.8%	31.6%	32.0%
Refuse Derived Fuels + CSP	22.6%	25.5%	26.5%	29.4%	29.8%	30.3%
Stubble + CSP	24.1%	26.8%	28.7%	32.9%	33.4%	33.6%

Table 4
Conversion rates (tonnes of feedstock to MWh electricity) for different feedstocks and power plant sizes.

Feedstock	5 MWe	10 MWe	15 MWe	20 MWe	25 MWe	30 MWe
Forestry residues, MWh/t	1.17	1.30	1.39	1.60	1.62	1.63
Bagasse, MWh/t	1.08	1.19	1.27	1.42	1.47	1.49
Urban wood waste, MWh/t	1.00	1.14	1.19	1.35	1.38	1.40
Refuse derived fuels, MWh/t	1.00	1.13	1.18	1.30	1.32	1.34
Stubble, MWh/t	0.94	1.05	1.12	1.28	1.30	1.31

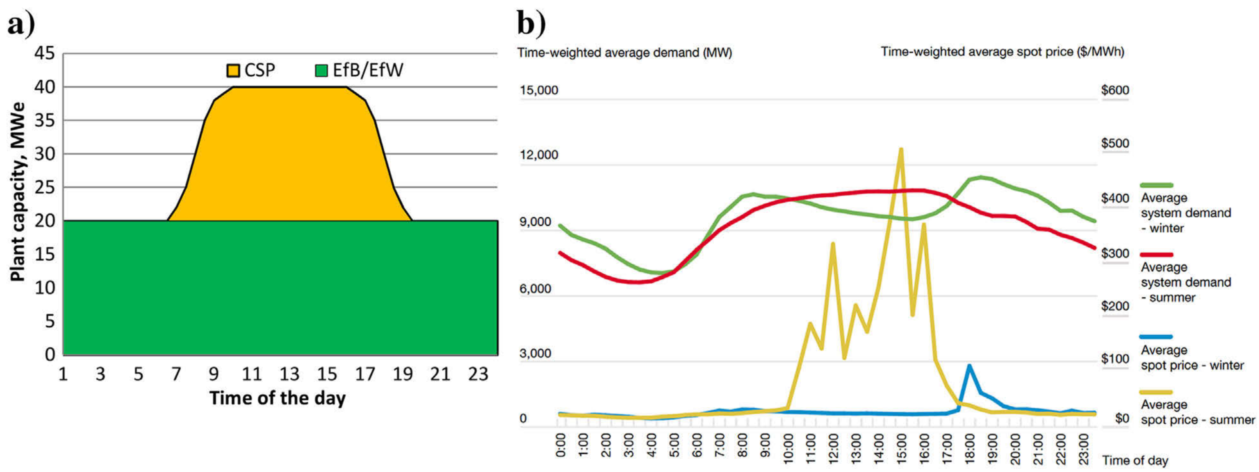

Fig. 1. a) CSP hybrid concept for a 40 MWe plant and b) NSW average weekdays system demand and spot price year ending 2010 [52].

being the most capital intensive component of a CSP plant [51] its size directly affects overall plant investment.

2.3. Constraints

Studies have shown significant differences between the theoretical and actual potential for CSP sites [21–25] and biomass resources [3,20,40] in Australia. To ensure an accurate resource assessment and identification of potential regions for CSP-EfB & EfW hybrids a number of technical, environmental and economic constraints were applied in this study.

2.3.1. Environmental

To minimise the environmental impact of CSP hybrid plants the following environmental constraints apply:

- No energy recovery from recyclable waste materials, only RDF and urban wood waste feedstocks.
- At least 1 t/ha of agricultural residues (crop stubble) in southern cropping regions and 1.5 t/ha in northern cropping regions retained to protect soils from the risks of erosion [39].
- All foliage or branches from forestry residues to be retained on site to assist maintenance of organic matter, and nutrients. Forest residues from plantations only.

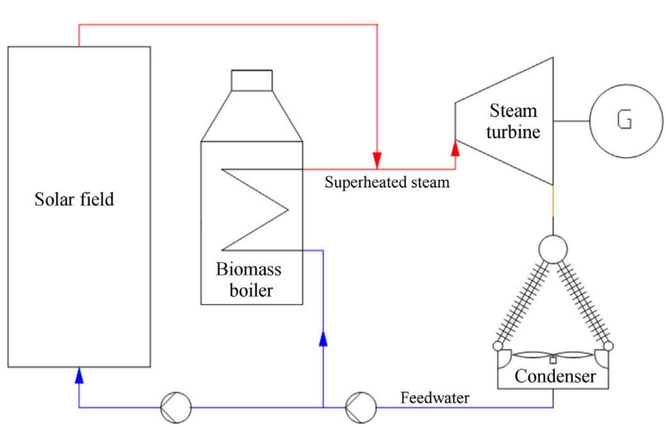

Fig. 2. Simplified process diagram for a CSP-biomass hybrid plant without steam reheating.

2.3.2. Technical

Various technical constraints in feedstock harvest, processing and conversion were applied considering constraints. They include:

- Capacity factor of 91.3% (8000 h/year) for EfB & EfW and 18% (1.577 h/year) CSP component.
- CSP plants with direct steam generation capabilities from 400 to 540 °C.
- Sufficient EfB/EfW feedstock in a 50 km radius to continuously operate the biomass component of the 5–60 MWe hybrid power plant at full capacity.
- Plant to be located within a 50 km distance to existing transmission infrastructure.
- Facilities not considered in DNI areas <18 MJ/m^2/day.
- Stubble cannot practically be cut lower than 12.5 cm [53].

2.3.3. Economic

High level economic constraints were applied in regards to feedstock supply, plant size, and electricity off-take. A detailed economic evaluation is not part of this study but scope for further work requiring detailed local information, such as labor and transport costs. The constraints include:

- Feedstock within approximately 50 km radius around the power lines to limit transport distance of feedstocks and access of CSP facility to electricity grid.
- At least a 5 MWe plant capacity to gain economy-of-scale benefits and maximum 60 MWe.

2.4. Technology selection

To start implementing CSP-EfB & EfW hybrid plants immediately, the use of mature technologies is essential. For this reason grate and fluidised bed combustion system are considered for all solid feedstocks and gasification with syngas firing in a boiler only for clean biomass.

CSP technologies considered to directly generate 400–540 °C steam are linear Fresnel and solar towers. Both technologies have >5 MWe plants in operation and under construction, e.g. 5 MWe Kimberlina Fresnel plant in the U.S [54], 2× 125 MWe Reliance Fresnel project in India [54], 5 MWe Sun Sierra tower plant in the U.S [55], and 3× 130 MWe Ivanpah tower plant in the U.S [56]. All the solid feedstocks considered can readily achieve steam

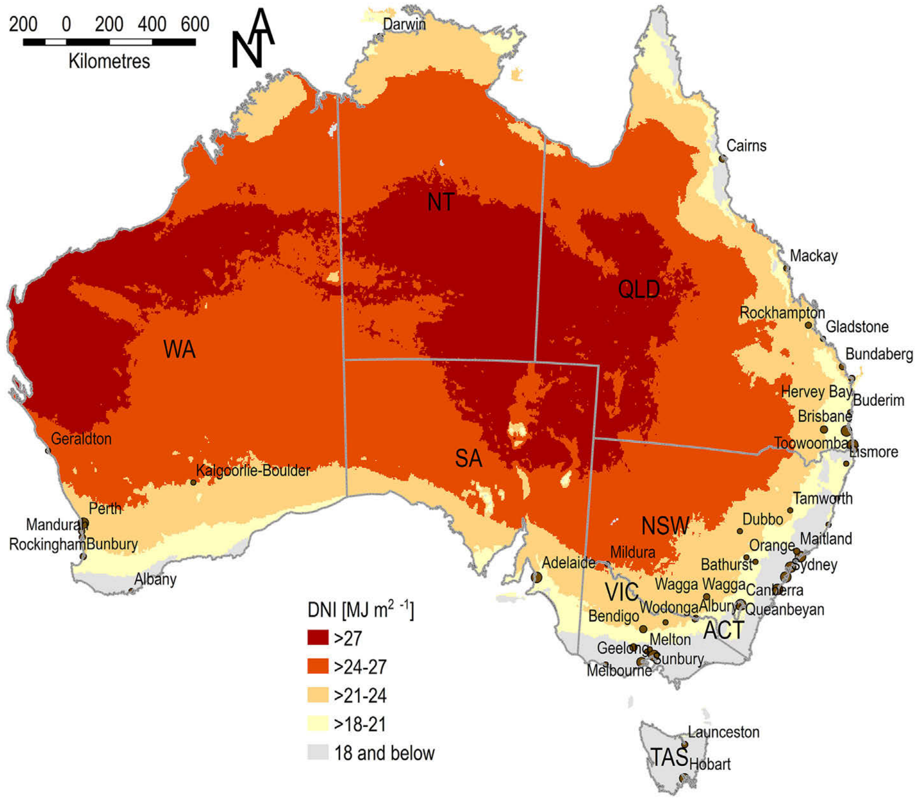

Fig. 3. Average daily direct normal irradiance across Australia showing >24–27 MJ/m^2/day (high DNI category), >21–24 MJ/m^2/day (medium DNI category) and >18–21 MJ/m^2/day (low DNI category) for CSP-EfB & EfW plants.

temperatures >400 °C and reducing the EfB/EfW plant's steam temperature would unnecessarily decrease the feedstock conversion efficiency. Therefore, the most mature parabolic trough technology using thermal oil is not considered as the oil's thermal stability limits steam temperatures to 385 °C. Since linear Fresnel steam temperatures at commercial scale are currently limited to a maximum of 500 °C [57] the technology is best suited for CSP hybrids using urban wood waste and RDF [58]. Solar towers are considered the best CSP technology for hybrids using clean biomass feedstocks, such as woodchips or straw [58], with steam temperatures >500 °C.

3. Results

This section outlines the energy resources, electricity and greenhouse gas potential, most prospective regions as well as the economic impact of CSP-EfB & EfW hybrid plants in Australia.

3.1. Solar resource

The solar resource in Australia is among the best in the world [59] with the theoretical potential to provide all of Australia's energy needs. As almost all CSP plants worldwide operate in DNI areas ≥20 MJ/m^2/day, we have assumed that this is a typical requirement of standalone CSP plants. Based on 1995–2011 DNI data by the Bureau of Meteorology [36] a significant part of Australia meets this criterion (Fig. 3). However, the comparatively high capital costs of CSP, traditionally low wholesale electricity prices, the lack of stable investment incentives, and the need to build new transmission infrastructure to access the highest DNI areas has proved a barrier to the construction of plants.

Cost savings through the joint use of equipment allow CSP-EfB & EfW hybrid plants to be considered in areas with a DNI ≥17 MJ/m^2/day [60] and the Termosolar Borges commenced operation in a lower than usual DNI area recently, 18 MJ/m^2/day [18]. Compared to standalone CSP plants new hybrids can realise investment reduction in excess of 20% [10,48,61] which offsets the 10.3% investment increase for a larger solar field in a 18–21 MJ/m^2/day DNI area. Therefore this assessment considers three DNI categories for CSP-EfB & EfW hybrid plants (Fig. 3), >24–27 MJ/m^2/day (high DNI category), >21–24 MJ/m^2/day (medium DNI category), and >18–21 MJ/m^2/day (low DNI category).

3.2. Biomass feedstock

Biomass production systems can have economic benefits through diversification of farming products and for areas of low agricultural production value. In many parts of the world, including Australia, biomass is contentious in the public domain, with the food versus fuel debate dominating the discussion. This assessment focuses on existing biomass resources and only considers existing crops or waste residues. It uses the approach taken by Farine et al. (2011) [3] which applies simple sustainability constraints to the proportion of biomass removed from current agricultural and forestry production systems. Feedstocks include bagasse, stubble, plantation residues and urban wood waste as in Farine et al. (2011). This assessment includes copper chrome arsenate treated timber as several plants operate successfully on this feedstock worldwide, such as the 20 MWe combined heat and power plant Berlin-Neukölln in Germany [62], and because this material poses environmental problems in landfills, e.g. leachate and methane formation.

The total yearly biomass feedstocks in suitable DNI areas amount to 21,334 kt and have calorific values from 15.7 to 19 MJ/kg (Fig. 4 and Table 5).

3.3. Waste feedstocks

RDF is produced from municipal, commercial and industrial waste streams by removing recyclable materials, such as plastics and metals, inert materials, such as glass and bricks, and organic materials, such as garden and food waste. RDF preparation systems and energy recovery technologies are well established [41], with many commercial plants worldwide. RDF has a renewable energy content of 40–60% [63], a high calorific value between 11.7 and 31.6 MJ/kg [64] and is more consistent than unsorted wastes, which has positive flow-on effects in the power plant, such as better combustion performance [65]. Demand for RDF as a sorted waste product also maintains the waste recycling priority and can divert waste from landfill.

The Australian waste quantities from MSW (municipal solid waste), commercial and industrial waste, and construction and demolition waste streams in 2006–07 amounted to 43,777 kt, of which 52% was recycled with the remaining 48% destined for landfill [66]. Post recycling, one tonne of waste per person was landfilled. Currently, global RDF quantities range from 23 to 55% of the waste stream input [41–43] and this assessment assumes an Australian average RDF quantity of 0.4 t/person/year. This leads to a total yearly RDF feedstock potential of 2631 kt for suitable DNI areas (Fig. 5 and Table 5).

3.4. Electricity and greenhouse gas abatement potential

Currently, CSP-EfB & EfW hybrid plants within 50 km buffers around existing transmission infrastructure (Fig. 6), have a combined annual electricity potential of 30.8 TWh/year for single-feedstock and 33.5 TWh/year for multiple-feedstock plants (Table 5). This is 20% higher than only using the biomass resources for power generation. The single-feedstock potential equals 11.8% of all electricity (including off-grid electricity) generated in Australia in 2008–09 [46] and the multiple-feedstock potential equals 12.8%. This also would cover 74% of the Australian Government's 2020 renewable energy target of 45 TWh [67]. When considering only DNI areas >21 MJ/m^2/day the potential is with 21.6 TWh for single-feedstock hybrids and 22.6 TWh for multiple-feedstock hybrids still significant equalling 8.3% and 8.7% of the total 2008–09 Australian electricity.

The high DNI category (>24–27 MJ/m^2/day) has with 3 TWh the lowest annual electricity potential, which consists to 98% of CSP-stubble hybrid plants. The annual electricity potential in the medium DNI category (>21–24 MJ/m^2/day) is 19.6 TWh, which is the highest of all areas and is also dominated by stubble. The wood

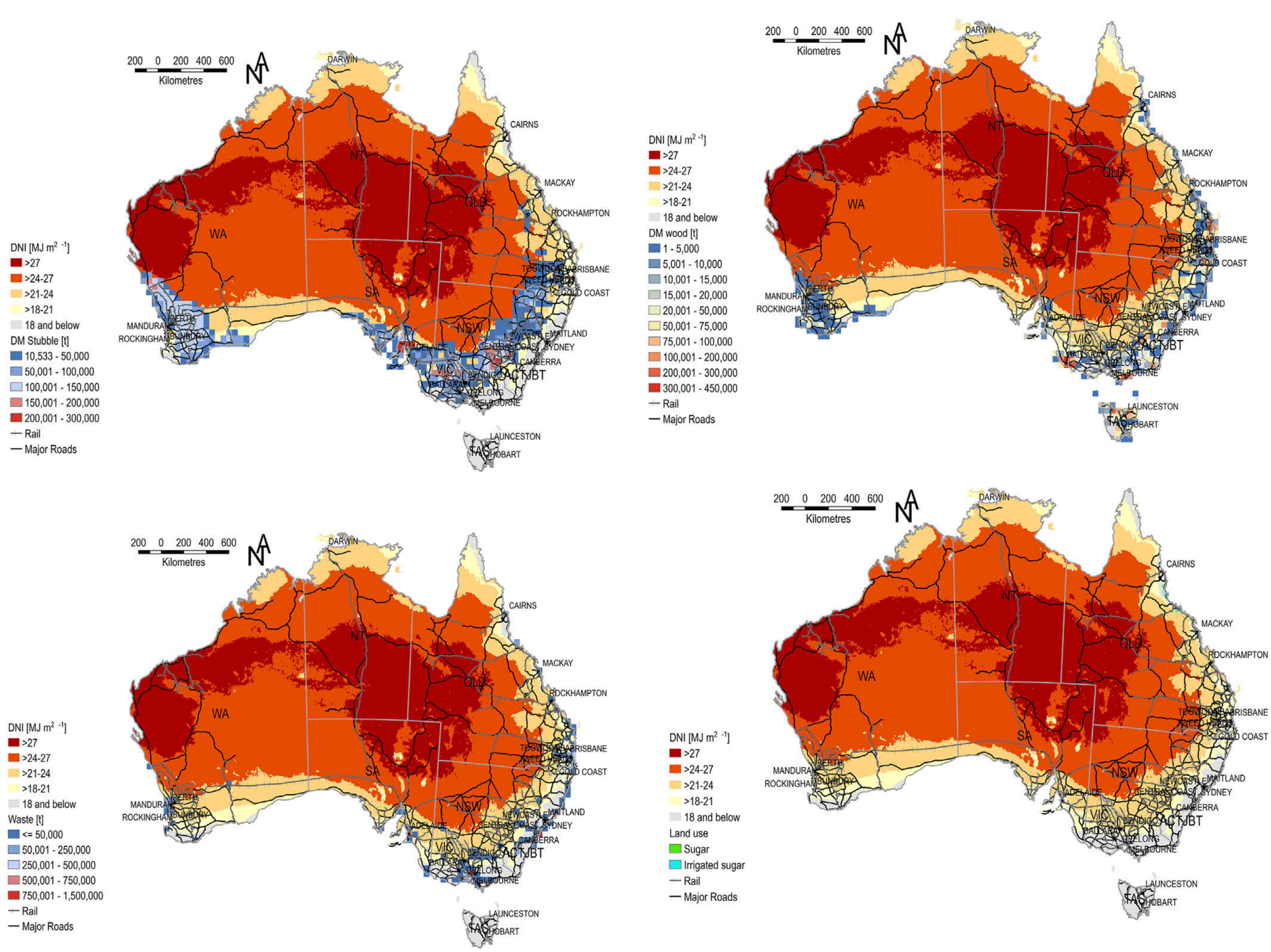

Fig. 4. Potential biomass availability in Australia overlayed with DNI; Stubble (top left), forestry residues (top right), urban wood waste (bottom left) and bagasse (bottom right).

Table 5
Annual feedstock, electricity and CO_2 abatement potential for CSP hybrid plants in Australia.

	Low DNI category >18–21 MJ/m^2/day	Medium DNI category >21–24 MJ/m^2/day	High DNI category >24 MJ/m^2/day	Total
Feedstock, dry t/a				
Stubble	1,800,000	11,407,000	2,328,000	15,535,000
Forestry residues	2,043,000	300,000	–	2,343,000
Wood waste	2,071,000	1,359,000	26,000	3,456,000
RDF	1,391,000	1,215,000	25,000	2,631,000
Multiple-feedstock	8,608,000	15,502,000	2,447,000	26,557,000
Capacity potential, MWe				
Stubble + CSP	450	3080	630	4160
Forestry residues + CSP	540	80	–	620
Wood waste + CSP	560	390	6	956
RDF + CSP	370	320	5	695
Total single-feedstock hybrids	1920	3870	641	6431
Total multiple-feedstock hybrids	2280	4090	630	7000
Generation potential, MWh/a				
Stubble + CSP	2,155,000	14,749,000	3,017,000	19,921,000
Forestry residues + CSP	2,586,000	384,000	–	2,970,000
Wood waste + CSP	2,682,000	1,868,000	29,000	4,579,000
RDF + CSP	1,772,000	1,533,000	24,000	3,329,000
Total single-feedstock hybrids	9,194,000	18,532,000	3,070,000	30,796,000
Total multiple-feedstock hybrids	10,918,000	19,585,000	3,017,000	33,520,000
Total investment, AU$m				
Single-feedstock hybrids	11,600	20,500	3300	35,400
Multiple-feedstock hybrids	13,800	22,300	3400	39,500
Total CO_2 abatement potential, t/a				
Single-feedstock hybrids	7,110,000	15,048,000	2,574,000	24,732,000
Multiple-feedstock hybrids	8,560,000	15,933,000	2,529,000	27,022,000

waste and RDF potential is 3.4 TWh. The low DNI category (>18–21 MJ/m^2/day) has a lower 10.9 TWh annual electricity potential as it covers neither prime agricultural nor forestry regions within proximity to transmission infrastructure. Here, woody biomass and RDF estimates are lower and stubble contribution is increasing with higher DNI (Fig. 7). Still, the first CSP-biomass hybrid plant in the world is located in a 18 MJ/m^2/day DNI area [18], which shows that Australia has an excellent potential for CSP-biomass hybrids in this and higher DNI locations.

The electricity potential for CSP-EfB hybrids using multiple feedstocks is 8.8% higher than the potential for single-feedstock hybrids. The reasons for this are that multiple-feedstock plants qualify for some locations where a single feedstock would not suffice to operate a minimum 5 MWe CSP-EfB & EfW hybrid plant.

Stubble has the highest potential for CSP hybridisation accounting for 64% of the total electricity potential followed by urban wood waste with 15%, RDF with 11% and forestry residues with 10%.

Bagasse is already in use in Australia for electricity and process heat generation in sugar industry centers, mostly in Queensland [4]. Bioenergy assessments identify an annual electricity potential from bagasse of 2.2 TWh [3], but the material grows predominantly close to the coast where DNI values are lower than further inland.

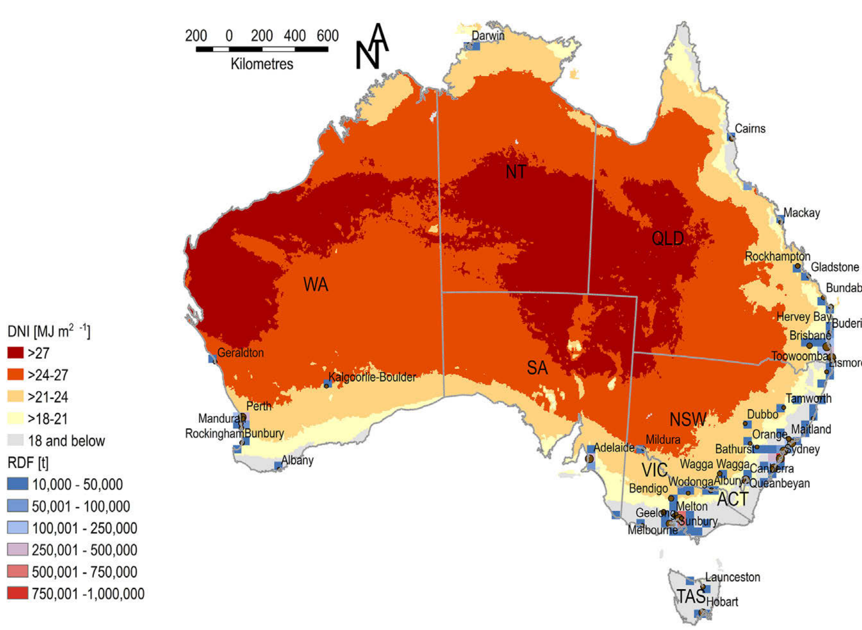

Fig. 5. Potential refuse derived fuel availability in Australia overlayed with DNI.

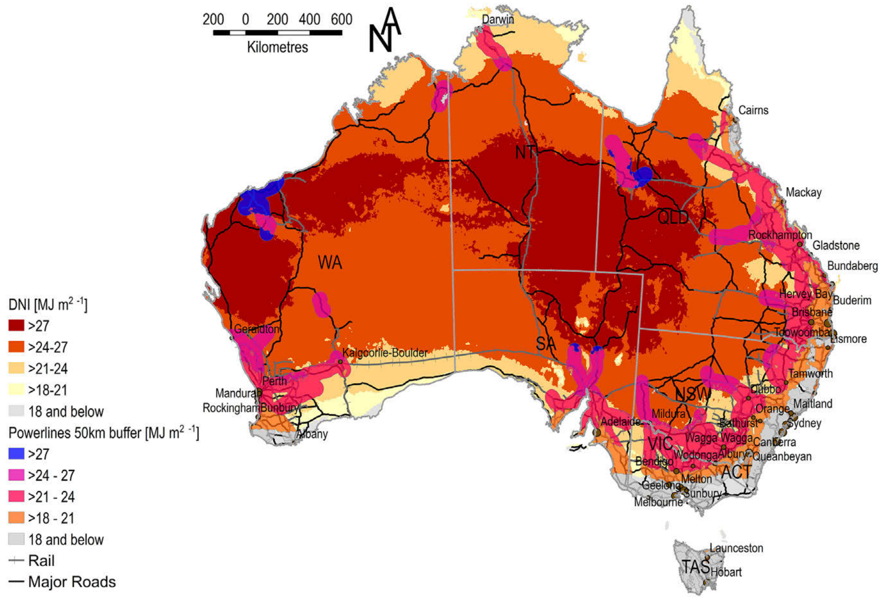

Fig. 6. 50 km distance areas around existing transmission lines, overlayed with different DNI categories.

Also the larger area requirement of a CSP-bagasse hybrid facility compared to a standalone bagasse electricity generator makes it more costly where it competes for higher value land. Identifying the few suitable sites would require more localised analysis and is scope for future work.

Considering the average 841 kg CO_2/MWh carbon intensity of Australian generation assets in 2010 [68], the exploitation of the CSP-EfB & EfW hybrid resources could, without consideration of biomass harvest and transport emissions, displace up to 27 million tones CO_2/year (Table 5). This equals 4.8% of all Australian 2009–10 CO_2 emissions [69].

3.5. CSP hybrid plant location potential

CSP-stubble hybrids could be located across large areas of Western Australia, New South Wales and Victoria while hybrids using urban wood waste and RDF are mostly associated with population centers, such as Mildura in Victoria or Perth in Western Australia (Fig. 8). The proximity of RDF and urban wood waste to urban centers makes them promising candidates for multiple-feedstock and cogeneration systems in terms of potential availability of biomass and proximity of demand.

From a DNI perspective the most prospective regions for CSP-stubble plants are between Griffith and Wagga Wagga in New South Wales, between Mullewa and Moora in Western Australia, and Cunderdin to Merredin in Western Australia with a total potential of >500 MWe each. The New South Wales region could accommodate several 5–55 MWe plants while the Western Australia regions could accommodate several 6–45 MWe. The Mullewa to Moora region has the highest DNI of all three regions. The two largest CSP-stubble hybrid plants with a capacity of 67 MWe and 72 MWe could be built in the north-eastern region of the York peninsula, South Australia.

The most prospective regions for CSP-forestry waste hybrids are around Gympie in Queensland with a total potential of 270 MWe (17–70 MWe plants) and Tumut in New South Wales with a total potential of 150 MWe (6–32 MWe plants). While the capacity potential is higher in Gympie, the DNI is better in the Tumut region. The pulp and paper mill in Tumut is currently investigating a 75 MWe expansion using waste feedstock [70] and a CSP component could further increase capacity or reduce the waste material quantity required.

The Mildura region in Victoria could provide the highest DNI for a CSP-urban wood waste hybrid with a capacity of 6 MWe.

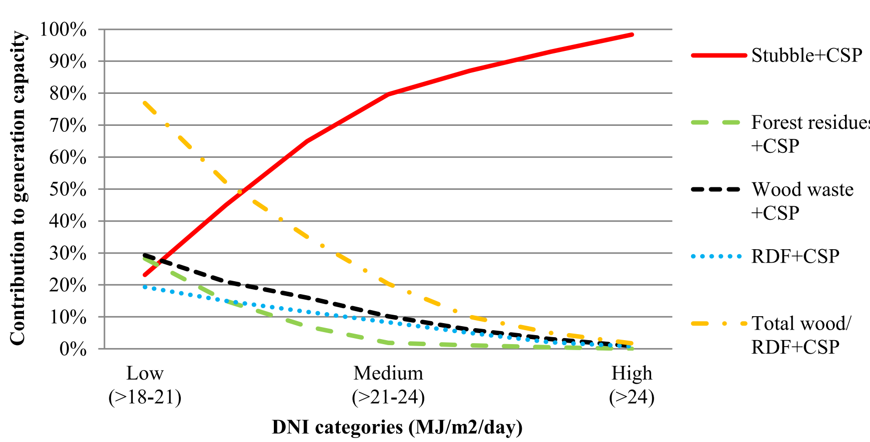

Fig. 7. Feedstock contribution to generation capacity in low, medium and high DNI areas; Data modelled discontinuously for three DNI categories and lines interpolated.

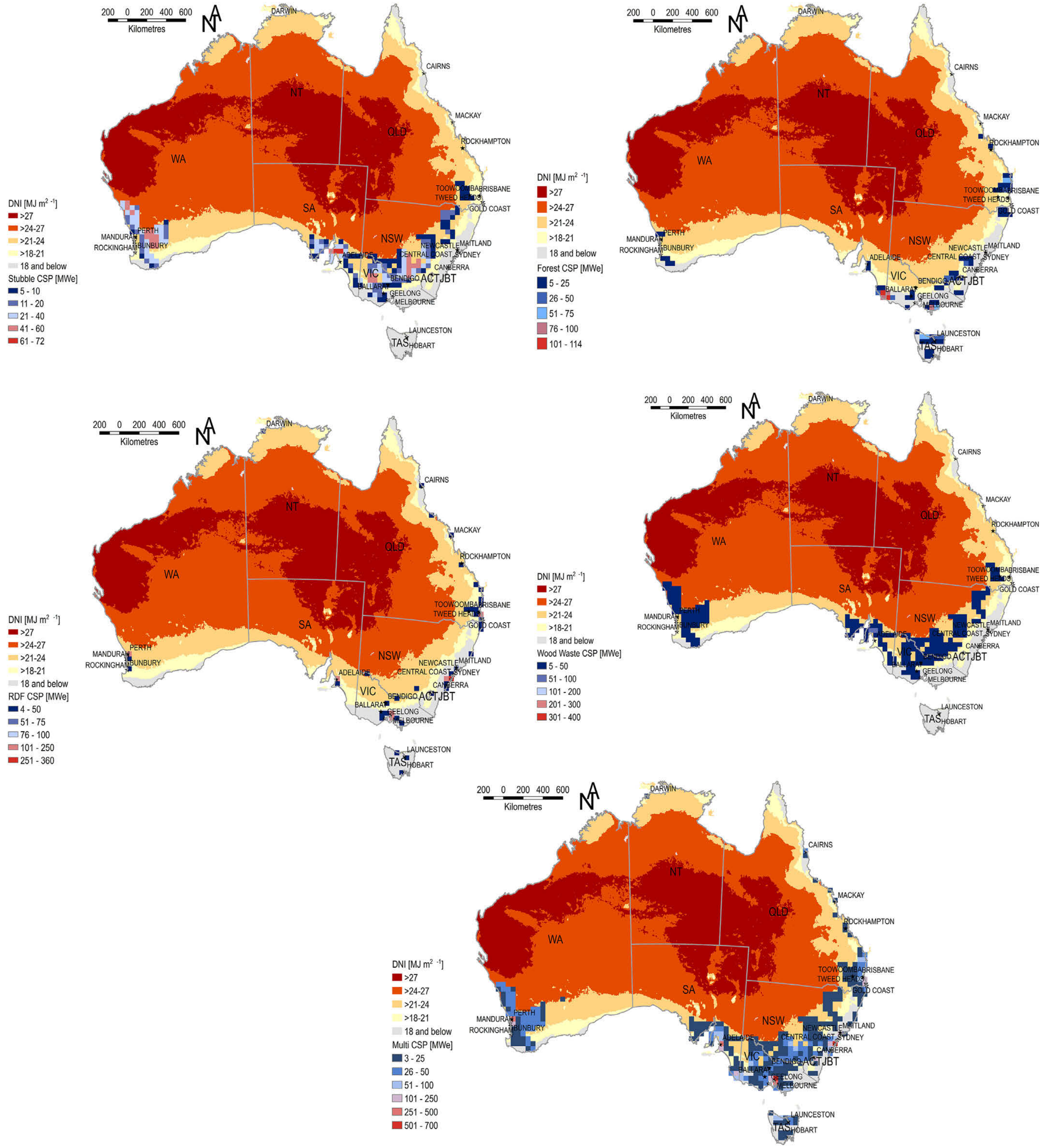

Fig. 8. MWe potential for CSP hybrids using stubble (top left), forestry wood waste (top right), urban wood waste (centre left), RDF (centre right) and multiple-feedstocks (bottom) across Australia.

Significantly larger plants are possible around Perth (up to 150 MWe), Brisbane (up to 115 MWe), Adelaide (up to 80 MWe) and Canberra (up to 40 MWe). With wood waste and RDF often arising in the same regions Mildura has the potential for a 5 MWe CSP-RDF plant, Perth for up to 115 MWe, Brisbane for up to 120 MWe, Adelaide for up to 90 MWe and Canberra up to 45 MWe. Due to the similar power plant design for wood waste and RDF, such as steam parameters and flue gas cleaning, both feedstocks should be used in multiple-feedstock plants to gain economy-of-scale benefits.

The most prospective regions for CSP multiple-feedstock hybrids in the higher DNI areas are identical to the areas of high stubble production but the generation capacity is slightly lower, circa 5% for Griffith to Wagga Wagga region, as even the mixture of stubble with small quantities of wood waste or RDF requires lower steam parameters to avoid high temperature corrosion issues. Hence, multiple-feedstock plants using feedstock with vastly different combustion properties that affect overall plant efficiency significantly are not recommended for regions with one dominant feedstock. For lower DNI areas CSP multiple-feedstock hybrids are more suitable as there is a variety of feedstocks available, mainly wood waste and RDF. The combination of these feedstocks with CSP can more than double the plant capacity for the potential areas around Perth (up to 270 MWe), Brisbane (up to 240 MWe), Adelaide (up to 175 MWe) and Canberra (up to 90 MWe).

Generally larger CSP power projects are economically more attractive than small ones as their specific investment is lower. In New South Wales, Western Australia, South Australia and Victoria several potential areas exist for 21–40 MWe CSP-stubble hybrid plants and even few 41–72 MWe installations (Fig. 8). CSP-forestry residue hybrids are mainly <25 MWe with only few regions in New South Wales and Queensland having potential for larger units. CSP-wood waste and RDF hybrids close to major urban centers could reach 150 MWe, while plants closer to rural townships would typically remain below 10 MWe. CSP-multiple-feedstock hybrids have with up to 270 MWe the potential for the largest plant sizes around Perth, Brisbane, Adelaide and Canberra but the identification of a specific site with sufficient size at an acceptable land price will be a challenge.

3.6. Economic analysis

The feedstocks used in a hybrid plant affect its investment, particularly in regards to boiler and flue gas cleaning design, and cycle efficiency (Table 1). To obtain a preliminary understanding of the most cost effective way to use the resources potentially available single and multiple-feedstock CSP-EfB & EfW hybrid plants have to be considered. While single-feedstock plants have higher efficiencies, typically less complex flue gas treatment, and a lower specific investment they cannot capitalise on economy-of-scale benefits as much as multiple-feedstock plants as single feedstocks typically arise in smaller quantities than feedstock mixtures. Realising the electricity potential for all feedstocks available in single-feedstock plants would require a total investment of AU$ 35.4b while multiple-feedstock plants would require AU$ 39.5b. The dominant role of stubble makes single-feedstock hybrids, on average, slightly more cost competitive than multiple-feedstock hybrids (AU$ 5.2m/MWe compared to AU$ 5.3m/MWe) because they can be efficiency optimised for one feedstock. Plant cost would increase/efficiency decrease when co-firing even small amounts of lower quality feedstock, such as wood waste or RDF.

4. Discussion

Investment into new technology is generally fraud with more uncertainties than proven technology. This is also the case for CSP-EfB & EfW hybrid plants. Uncertainties, such as investment differences in various locations, DNI data quality, alternative use of feedstocks, temporal feedstock availability, and impact of future climate change require consideration. Such issues must be considered carefully on a project by project basis to ensure successful implementation.

4.1. Economic implications

This analysis identified several areas in Australia that have sufficient feedstock and solar radiation for the development of CSP-EfB & EfW hybrid plants, which could reduce electricity related CO_2 emissions by up to 27 million tones/year. However, CO_2 reduction requires implementation of renewable energy technology on-ground at lowest cost. Due to the defined CSP capacity factor of 18%, higher DNI locations lead to a lower specific investment and electricity cost, so such locations should be preferred when sufficient biomass is available. Additionally, high DNI locations are usually in rural areas and hybrid plants could provide network benefits, such as increased grid stability and investment deferral in new transmission infrastructure. In Australia biomass is available in DNI areas suitable for standalone CSP plants (>20 MJ/m^2/day), which is an incentive to build hybrids as the CSP component would not suffer from lower than usual DNI levels.

The second most relevant cost reduction factor is deployment. Additional global CSP deployment is expected to reduce solar field costs by up to 40% by 2020 [71], which in turn could lead to CSP-EfB & EfW plant cost reductions of up to 21% by 2020. Lower costs would lead to more competitive CSP hybrid and standalone power plants in all DNI areas considered.

When assessing the impact of power plant projects on the Australian economy, not only the direct investment benefits should be considered but also the multiplier effect of benefits these projects create in the wider economy. In addition to the power plant the feedstock procurement has to be considered for CSP-EfB & EfW hybrids. A value-added multiplier effect for biomass plants, including feedstock procurement, of 1.42 has been used before [72] and seems also realistic for this assessment. CSP multiplier effects have been also investigated and a value of 2.3 is used in this assessment [73]. This assessment is based on 50% steam turbine capacity from CSP and 50% from EfB/EfW which leads to a combined multiplier of 1.86. Using this multiplier and assuming 29% of the plant investment flowing overseas for equipment manufacturing [73] the realisation of the single-feedstock CSP-EfB & EfW potential could lead to an overall financial stimulus of AU$ 46.7b and AU$ 52.2b for multiple-feedstock hybrids. Such an investment equals 3.5% of Australia's GDP in 2010–11 and 4% respectively [74].

4.2. DNI data quality

The annual electricity potential for CSP-EfB & EfW hybrid plants depends on the DNI input data, which tend to vary depending on data provider, time period considered, and data resolution. This assessment used daily average DNI data from the Australian Bureau of Meteorology [36] and the mapping results are similar to publications using data from NASA [9,75], or the German Aerospace Center [59]. Therefore the results are a reliable indication of the general potential but the use of other DNI sources might lead to slightly different results.

Our analysis is focused on regional CSP opportunities. Assessing the feasibility of a specific project requires more detailed DNI data to estimate the hourly, daily, and seasonal radiation variation more precisely. Methods exist to predict hourly data from DNI averages [76,77], but ground measured data are essential to verify the DNI models before committing funding for the construction of a CSP plant.

4.3. Alternative uses of biomass feedstock

While biomass may be available for power generation now, with oil prices generally expected to increase in the future, other industries will divert non-contaminated biomass, such as forestry residues, to higher value added products, e.g. biofuels or biochar. Also large amounts of biomass may already be committed to other purposes than electricity generation, e.g. plywood or paper industry production [20]. Biomass feedstock resource security needs to be considered carefully with long term feedstock supply contracts in place when planning a power station with an expected operational life of at least 25 years.

The low energy density of biomass requires significant feedstock quantities in the vicinity of typically large biofuel facilities which has implications in regards to continuous material availability, for example stubble potentially available for harvest has high annual variations [39], and transport costs, e.g. stubble transport cost increase from AU$ 8/t for 10 km, AU$ 12/t for 50 km to AU$ 18/t for 100 km [20]. Therefore, the cost of transporting biomass resources long distance to centralised production facilities may become prohibitive. Typically, electricity prices are higher in rural areas than main population centers, due to higher transmission losses and maintenance, and distributed electricity generators using the lowest cost locally available biomass/waste feedstocks could provide electricity and avoid transmission losses from centralised generators, which are usually fossil fuel fired [20]. In regions with a sufficiently high DNI, >18 MJ/m^2/day, the hybridisation with CSP is promising to gain economy-of-scale benefits, increase the use of local energy sources, and raise local power generation capabilities.

4.4. Temporal availability of biomass and solar resources

Agricultural and horticultural biomass residues as well as DNI vary throughout the year depending on the crop, weather conditions, harvesting cycles and the sun's angle of incidence. With forestry residues, plantation wood, urban wood waste, and RDF being more predictable feedstocks these could be/are already used in plants in Denmark [78] or Spain [79] to compensate the shortfall in less reliable feedstocks, such as stubble.

CSP-stubble hybrids have the highest annual electricity potential in Australia, but stubble potentially available for harvest is highly variable over the years, e.g. approximately 35 million tonnes in 2004 and approximately 7.5 million tonnes in 2003 [39]. Therefore stubble based CSP hybrids require a detailed feedstock availability/variability analysis and a conservative estimate of the continuously available feedstock potential. Rather than opting for a large plant, such as 50 MWe to obtain economy-of-scale benefits, a smaller unit, such as 30 MWe, has a higher probability of sufficient feedstock supply over its lifetime. Storing baled stubble is an alternative to minimise the risk of supply shortages [39].

To ensure continuous supply feedstock storage facilities are required for all biomass feedstocks. Also locating the plant in areas where crop and non-crop residues are available is beneficial as is the use of multiple feedstocks.

A low cost option is to oversize the start-up burners a biomass boiler requires, typically firing natural gas or diesel. Larger burners would allow plant operation at minimum load not only during supply shortages but also during equipment failures, such as conveyer belt breakdown. However, this option may not be competitive in areas where natural gas or diesel is not readily available.

With the DNI varying throughout the year, being higher in summer than winter, the thermal output of CSP plants can vary significantly depending on CSP technology and plant design, e.g. <50% of the design output in winter. Typically, the output of a biomass plant increases slightly in winter, due to lower ambient temperatures, but that is not sufficient to compensate the CSP shortfall. To smooth the annual electricity output, the solar field is typically oversized by up to 40%, which equals a solar multiple of 1.4. The larger field size increases investment but allows a higher annual energy yield therewith offsetting the additional investment without requiring thermal storage.

4.5. Impact of climate change

With climate change projected to increase annual Australian average temperatures by 0.6–1.5 °C by 2030 [80] the annual generation of a power station with air-cooling would decrease as higher temperatures reduce condenser performance. Assuming the predicted 0.6 °C increase the annual electricity output would decrease by 0.2% and 0.5% at 1.5 °C. The annual DNI would have to increase by 1% and 2.8% respectively to compensate these shortfalls. In Australia the surface solar radiation increased from 1994 to 2003 by an unspecified amount [81] but more data are required to reliably identify if the increase is sufficient to compensate the aforementioned generation decrease.

Another climate change impact on CSP-EfB hybrid plants is rainfall. High potential areas for such plants are in the wheat regions of New South Wales and Western Australia but these are also the regions that experienced very much below average rainfall for the period from 1997 to 2011 [80]. Longer droughts and more periods of heavy rather than normal rainfall can impact biomass production significantly, particularly considering that the rainfall in Australia is already highly variable. With the expectation of higher yearly variability in crop production, long-term feedstock storage is important to dampen the effects of variable feedstock availability.

4.6. Additional feedstock and energy potential

Identifying all potential biomass and waste feedstocks across Australia at a scale suitable for a CSP facility would be time consuming and expensive. It is appropriate to take a staged approach, using a high level reconnaissance approach first, identify prospective regions, and then conduct more detailed studies in the most prospective regions [82]. This assessment focuses on the materials outlined in Table 2 but acknowledges that other suitable feedstocks may exist.

Several agricultural regions exist in high DNI areas of New South Wales, Queensland, Victoria, South and Western Australia, and more detailed resource assessments in the future are likely to reveal additional biomass feedstocks from horticulture, cotton, olive, wine, and other industries. However, the nature of these feedstocks is diverse ranging from traditional biomass, such as wood waste from citrus farms, to exotic materials, such as olive pits or nutshells. This assessment, for example, identified a promising potential for stubble, urban wood waste and RDF for the Mildura region, in northern Victoria, where a biomass project currently under construction uses spent grape marc [83] rather than the regionally more abundant feedstocks. Further potential for a total of 120,000 t/a spent grape marc [84] exists in three DNI suitable sites in South Australia and New South Wales which is sufficient feedstock for three 5.2 MWe (25 GWh/year) CSP hybrid plants. Similarly, 181,500 t of almond shells and hulls were available in 2013 in South Australia and Victoria [85]. The material potentially available from the larger plantations would suffice to generate up to 213 GWh of additional electricity with CSP. With almond residues expected to increase to 238,500 t/a in 2015 [85], the electricity potential would increase to 284 GWh/year. In addition to biomass further CSP-EfW opportunities exist for remote towns and mines, such as 13.5 MWe Boodarie EfW proposal in Western Australia [86]. Adding a CSP component to this plant would allow a total generation capacity of 27 MWe increasing the annual electricity output to 130 GWh. It is very likely that similar opportunities exist across Australia and the potential of these materials has to be assessed on a regional to local basis to gain a suitable picture of feedstock quantities for site specific CSP-EfB & EfW developments.

Agroforestry is another option to increase the potential for CSP-EfB hybrid plant across Australia and in Western Australia more than 12,000 ha of mallee trees have already been planted in narrow belts to enhance erosion and salinity control [87]. The material is suitable for power generation but the existing mallee resource within a 100 km radius of any point is likely to be less than 50,000 t/a [4], which is not sufficient to operate a small power station. The situation in the Mildura region is similar with regards to material density [88]. However, further agroforestry and biomass production expansions could supply sufficient material for several smaller, 5–10 MWe, distributed generation plants in the Mildura region [31].

Adding thermal storage is another option to increase the electricity potential of CSP-EfB & EfW hybrid plants and might be economically viable at the end of this decade with thermal storage prices expected to decrease from AU$ 90/kWhth to AU$ 22/kWhth in 2020 [71]. The well proven 7.5 h thermal storage concept, as applied in the Andasol parabolic trough plants in Spain [89], could increase the CSP capacity factor in hybrid plants to 40% therewith increasing the annual electricity potential to 37 TWh for single and 40.3 TWh for multiple-feedstock hybrids.

4.7. Limitations

This study aims to identify the electricity potential and prospective regions for CSP-EfB & EfW hybrid plants in Australia. It does not provide specific sites for such plants as site selection depends on criteria that have to be addressed in a local study, such as land ownership and other land users. Also the electricity potential of power plants can change with its location, due to grid constraints and ambient temperatures.

Thermal storage in the CSP plant is not considered in this assessment but provides scope for future study as it could increase the electricity generation potential significantly. The optimum thermal storage capacity is site specific, depending on time and lengths of high electricity prices/demand. It is therefore complicated to incorporate this for an Australia wide assessment but the numbers provided outline the general potential of thermal storage.

While this paper provides the investment data these are generalised to cover all of Australia. Identifying the detailed investment and economic viability of a power station requires an understanding of local prices for electricity, fuel, labor, and equipment.

The CO_2 abatement potential CSP-EfB & EfW hybrid plants depends on various factors, such as fuel composition and transport distances. Assessing this nationwide required some generalisation with results that are not as detailed as a local assessment based on site specific data.

In summary this paper provides a high-level assessment of the CSP-EfB & EfW hybrid plant potential in Australia. Identification of the best specific sites for such projects requires further localised studies with more detailed technical and economic assumptions.

5. Conclusions

The potential for CSP-EfB & EfW hybrid plants in Australia is significant with a total electricity potential within 50 km distance around existing transmission lines of up to 33.5 TWh/year, equivalent to 12.8% of all electricity generated in Australia in 2008–09. The potential for CSP hybrids using multiple feedstocks is 8.8% higher than the potential for hybrids using a single feedstock as multiple-feedstock plants qualify for more locations. The average investment in single-feedstock hybrids is slightly lower than in multiple-fuel hybrids as such plants do not require more expensive equipment capable of handling several feedstocks. The feedstock with the largest individual potential is stubble, 64% of total generation, followed by urban wood waste, 15% of total generation.

The majority of identified locations could provide biomass for 5–25 MWe CSP-EfB & EfW hybrid plants. Several regions exist in New South Wales, Victoria, Queensland, Western and South Australia for up to 50 MWe installations while fifteen locations could support even larger capacities.

Considering the average 2010 carbon intensity of Australian generation assets, the exploitation of the CSP-EfB & EfW hybrid resources could displace up to 27 million tones CO_2/year, which equals 4.8% of all Australian 2009–10 CO_2 emissions.

This assessment of feedstocks and most prospective regions for CSP-EfB & EfW hybrid plants provides guidance to project developers and researcher for more detailed local resource and site identification studies in the future. In addition, local biomass feedstocks, such as spent grape marc or almond shells exist, thus increasing the annual electricity yield potential. However, it is not possible to assess these localised feedstocks on a nationwide basis.

CSP-EfB & EfW hybrid plants are suitable for several regions in Australia and there is the potential to realise CSP installations at significantly lower cost than standalone CSP plants. With the first CSP-EfB hybrid in Spain demonstrating the benefits of such hybrids and providing financiers with confidence in the technology, similar systems could be seen in Australia within the next years. However, Australia's electricity production is built on a large and cheap coal resource, resulting in low wholesale electricity prices. Renewable energy, including CSP, has to compete with coal, taking into account investment, operating/maintenance costs, avoided CO_2 emissions, and returns from renewable energy certificates. Thus, future work for CSP developments requires an economic analysis considering these costs and returns from power production.

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4.3 CSP technology selection

The following publication analyses various currently available CSP technologies in regards to their suitability for hybridisation with Rankine cycle power plants and it identifies the most promising ones for various integration options, not only with biomass and waste feedstocks but also with natural gas and coal. The focus of this research is on the hybridisation of CSP with biomass and waste materials. However, the assessment methodology was applied for natural gas and coal hybrids and therefore the results are shown even though they are not part of this research. This analysis was the first part of the research project to be completed, and it provided important information for the other research components.

An industry engagement workshop on 21 July 2011 at the University of Technology, Sydney was a key part of this analysis and provided not only the CSP technology ratings but also valuable input into the research project from various industry professionals.

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Review

Concentrated solar power hybrid plants, which technologies are best suited for hybridisation?

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ABSTRACT

This assessment aims to identify the most suitable concentrated solar power (CSP) technologies to hybridize with Rankine cycle power plants using conventional fuels, such as gas and coal, as well as non-conventional fuels, namely biomass and waste materials. The results derive from quantitative data, such as literature, industry information and own calculations, as well as qualitative data from an expert workshop. To incorporate the variety of technology criteria, quantitative and qualitative data the Analytical Hierarchy Process (AHP) is used as the multi-criteria decision making (MCDM) tool. Only CSP technologies able to directly or indirectly generate steam are compared in regards to feasibility, risk, environmental impact and Levelised Cost of Electricity (LCOE). Different sub-criteria are chosen to consider the most relevant aspects. The study focuses on the suitability of CSP technologies for hybridisation and results obtained are reality checked by comparison with plants already being built/under construction. The results of this assessment are time dependant and may change with new CSP technologies maturing and prices decreasing in the future.

Key findings of this assessment show that Fresnel systems seem to be the best technology for feedwater preheating, cold reheat steam and <450 °C steam boost applications. Parabolic troughs using thermal oil rank second for all CSP integration scenarios with steam temperatures <380 °C. Generally, for steam temperatures above 450 °C the solar towers with direct steam generation score higher than solar towers using molten salt and the big dish technology. At and above 580 °C the big dish is the only alternative to directly provide high pressure steam.

In addition to a general CSP technology selection for hybridisation the framework of this study could be used to identify the most suitable CSP technology for a specific CSP hybrid project but this requires detailed information for direct normal irradiance, climate conditions, space constraints etc to provide reliable results.

1. Introduction

In recent months the CSP industry has faced increasing competition from the photovoltaic (PV) industry as the latter's manufacturing costs are decreasing rapidly due to mass manufacturing and associated learning curves. The conversion of the first 500 MW_e phase, and potentially second, of the 1000 MW_e Blythe Solar Power Project, US from parabolic trough to PV is the most prominent example so far [1]. In order to remain competitive the CSP industry has to emphasise the benefits of energy dispatchability, and also to further reduce plant cost.

Demonstrating the benefits of energy dispatchability through thermal storage is relatively simple as several plants are equipped with 7.5 h [2] to 15 h [3] full-load storage systems. In summer the 15 h storage allows 24/7 base load generation and intermittent load generation in winter. However, thermal storage is still expensive, currently costing around US\$90/kWh_{th} [4]. Through innovation and learning experiences these costs are expected to decrease to US\$22/kWh_{th} by 2020 [4]. More cost competitive thermal storage technologies would give CSP a unique advantage over PV but are not available yet. Hence, hybridising a CSP steam generator with a host Rankine cycle plant makes sense as the host plant can provide the additional energy required at lower cost until more cost competitive thermal storage is available. Currently, a 7 h thermal storage for a 50 MW_e parabolic trough plant contributes 9% to the required

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investment [5]. Reducing the investment by 9% while decreasing plant complexity and enabling better energy dispatchability is likely to put CSP systems into a better commercial position.

Reducing capital expenditure (CapEx) is more difficult and all technology providers are working intensively on this. Compared to the time consuming re-design of mirrors, support structures, absorber tubes etc a rapid way to reduce CapEx is the hybridisation of CSP steam generators with other Rankine cycle based power generation assets. This could be in the form of retrofits such as the example at Liddell, Australia [6] or new purpose build plants such as Kuraymat, Egypt [7]. The joint use of equipment, such as steam turbine, condenser, building infrastructure and feedwater equipment, can provide significant LCOE reductions, up to 28% [8], which would help the CSP industry to start building more plants, ramping up manufacturing capabilities as well as gaining relevant project implementation experience. The wind and PV industries realised learning curve cost reductions of 15% and 20% when doubling cumulative deployment [9] and the CSP business could benefit similarly. At the same time plant operators and financiers will become more familiar with the variety of CSP technologies and their specific benefits. Another benefit would be projects with smaller investment requirements, which reduces financial risk. This would particularly help newly developed CSP technologies to prove their capabilities. Due to a minimum CSP plant efficiency scale of 10–100 MW_e for standalone systems [4] such projects incur a higher financial risk over kWe scale PV systems. However, CSP add-on references exist at sizes of only 9 MW_{th} [6].

In addition to energy dispatchability and cost benefits CSP hybrid plants expand suitable plant locations from usually arid to semi-arid and temperate regions. While CSP standalone plants typically require a direct normal irradiance (DNI) $\geq$2000 kWh/m^2/year CSP hybrids can be located in areas $\geq$1700 kWh/m^2/year [10]. This moves CSP out of remote desert type areas closer to load centres and back-up fuel sources such as biomass in agricultural regions and waste materials in urban areas.

A number of plants combining CSP and coal/natural gas are already in operation in Egypt [7] and the US [11], as well as under construction in Australia [12], Iran [13] and Morocco [14]. These projects prove that the hybridisation of CSP with other energy sources has benefits in terms of CapEx and energy dispatchability.

Identifying the ideal CSP technology for a specific power plant location is highly dependant on local conditions, for example DNI and climate, as well as site specific constraints, e.g. land and water availability as well as topography. As it is impossible to assess all suitable locations for CSP hybrid plants in one comparison, this study provides a general multi-criteria based approach to identify the most suitable CSP technologies for hybridization with Rankine cycle power plants using a number of fuels. This has already been done for standalone solar plants [15] but not yet for hybrid configurations. The generic input data provided can be substituted with site specific data allowing the programme to be used for broad as well as specific investigations.

2. Technology ranking process

The technology ranking process used consisted of three consecutive steps:

- Selection of the main criteria and sub-criteria;
- Data collection; and
- Criteria weighting at an expert workshop using the Analytical Hierarchy Process.

2.1. Criteria selection

To make a holistic comparison it is necessary to select criteria assessing the feasibility, risk, environmental impact and LCOE of suitable CSP technologies. Each of these criteria groups is divided into sub-criteria, see Fig. 1, except the LCOE as this information already includes capital, operational and financing expenditures as well as parasitic losses. At the workshop (described in Section 2.4), all criteria were rated individually by the participants.

2.1.1. Feasibility

In this study the feasibility of integrating a CSP technology into a host plant comprises the peak solar to electricity efficiency, suitable operation range as well as the maximum site gradient.

The peak solar to electricity efficiency is chosen as the annual efficiency varies too much with the project location and is therefore not suitable for a general assessment. The annual efficiency would be preferred for a site specific CSP assessment.

The suitable operation range is selected to outline the reference case for each technology (in MW_{th}) with plants in operation and under construction being considered. In the biomass/waste hybrid scenario a 20 MW_{th} CSP contribution is assumed but not all CSP technologies considered have references in this range.

The maximum site gradient is important to assess the locational flexibility. Particularly smaller plants closer to urban areas might not have graded areas for a CSP system. Hence the higher the possible site gradient of a technology the better. The maximum site gradient of 12° [16] is determined by the tipping angle of a water truck cleaning the heliostat or mirror field.

2.1.2. Risk reduction

Risk reduction includes the technical maturity, plant complexity and integration simplicity.

The technology maturity is assessed by the largest plant (in MW_e) with financial approval. Obtaining financial approval for high

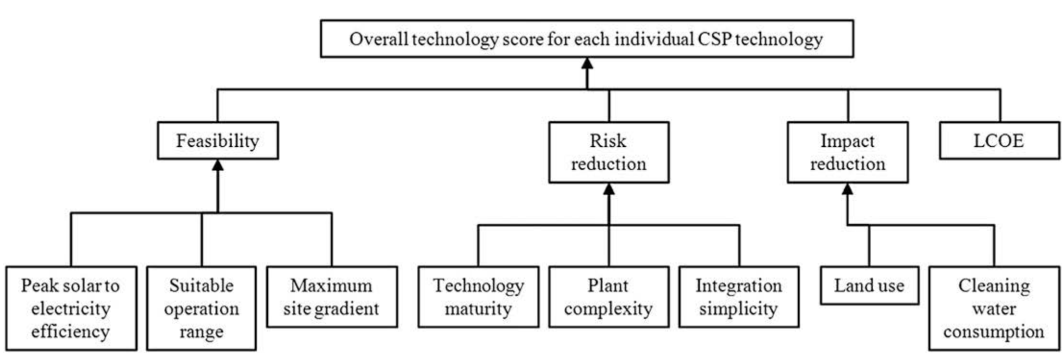

Fig. 1. Criteria hierarchy.

CapEx projects is a clear indicator of how comfortable financiers are with a technology in terms of performance, reliability and risk mitigation.

Plant complexity assesses the number of working fluid cycles required. DSG plants require only one cycle while others, such as thermal oil or molten salt, require two. Generally, the lower the number of system cycles the lower the technical, operational and maintenance risk. Specific technical issues, such as two-phase flow related problems in DSG plants, are a reflection of the technology maturity, where parabolic trough (thermal oil) plants score best due to their long track record. However, even these plants still have some technical issues requiring further improvement, e.g. optimizing flexible hoses connecting the absorber tubes to distribution/collection headers.

The criterion for the integration simplicity is the steam temperature of the CSP technologies. Being able to produce the steam parameters required by the host plant is essential to integrate a CSP steam generator and therefore this is an exclusion criterion. In case a CSP technology is unable to provide the steam parameter required by the host plant it is not further considered.

2.1.3. Environmental impact

The environmental impact reduction comprises land use and cleaning water consumption.

The land use in m^2/MWh/a is important for environmental but also commercial reasons. Particularly, CSP systems close to urbanization have to expect higher land cost and therefore minimise land use.

In relation to the water consumption (litre/MWh_e), only cleaning water for heliostat and mirror washing is considered as the Rankine cycle connected to the host plant is a closed system and blowdown losses are expected to be similar across all CSP technologies.

2.2. Data collection

To identify relevant data for the chosen criteria an extensive literature review is essential. Most of the data given in Section 3 derive from publicly available literature with additional information from industry sources as well as own engineering work. The LCOE obtained were from different sources, are inflation adjusted and converted into US$.

Technologies not directly or indirectly generating steam to feed into a Rankine cycle are excluded, e.g. Dish-Stirling systems.

2.3. Analytical hierarchy process

The Analytical Hierarchy Process (AHP) provides a comprehensive and rational framework for structuring complex decision problems and comparing the different alternatives considered. The method is widely used in the research and industry world, including assessments comparing fossil fuels with renewable sources [17,18] and different CSP standalone technologies with each other [15].

Because of the significant number of technical, risk, environmental and economic based criteria as well as the use of qualitative and quantitative data the AHP is chosen for this assessment. The AHP decomposes a complex problem into several sub-problems, such as economic and environmental impact, and therewith provides an easy to understand path for multi-dimensional decision making [19]. This is essential to include the different aspects of CSP technologies and was a main reason for selecting the AHP.

The problem decomposition takes place by identifying criteria (main- and sub-criteria) relevant to the problem and organizing them in levels of hierarchy, see Fig. 1. The AHP can use precise criteria data (quantitative information) to compare the different options as well as the decision makers' personal judgements (qualitative information). Subsequently, quantitative and qualitative information are merged to calculate the total score for each option.

As we identified quantitative data for all criteria this study used the original AHP with the following relationship [19] rather than the revised pairwise comparison matrices [20]:

$$\text{AHP score} = \max \sum_{j=1}^{n} a_{ij} w_j,$$

for $i = 1,2,3, \ldots, m$, $a =$ alternative and $w =$ criteria weighting.

After merging quantitative and qualitative data the alternative with the maximum score is considered the preferred option. The different criteria and its hierarchy in this assessment are shown in Fig. 1. The qualitative data used are shown in Tables 1\and 2, while the quantitative data are outlined in Tables 3–6. Due to the availability of quantitative data for all criteria of each CSP technology an expert workshop was organized to specifically identify the relevance of the individual criteria.

To accommodate uncertainties in the input data ±10% sensitivity is applied to all results.

2.4. Workshop

To rate the different criteria and sub-criteria from 1 to 9 [21], with 9 being of extreme importance and 1 being of no importance, we organized an expert workshop with 49 professional participants and conducted another 3 interviews. The workshop method was chosen to increase judgement accuracy [22] and subsequent interviews were only conducted for people who had other commitments on the day of the workshop.

After presenting the CSP technologies and criteria, and explaining/discussing the selected quantitative data all participants individually rated the importance of the various CSP criteria for the different host plant scenarios (Section 4). All individual participant ratings were combined and the average for all criteria identified. The form given to the participants for the non-conventional fuel hybrid scenarios is shown in Fig. 2. The same forms with adapted data were provided for the natural gas and coal scenarios. Of all participants 40 result sheets were evaluable, with the remaining not being filled in properly or not returned. Despite this the number of criteria ratings obtained is considerable compared to other workshops with significantly fewer people [15]. The University of Technology Sydney's Human Research Ethics Committee checked and approved the design and conduct of the workshop and interview activities.

Table 1
Average score of rating criteria and score differences by participant group.

Criteria	All	ΔO	ΔTP	ΔC	ΔR	ΔUnknown
Peak solar to electricity efficiency	6.52	−0.52	−0.12	−0.58	0.91	0.36
Suitable operation range	6.85	1.05	−0.08	−1.45	−0.33	−0.02
Maximum site gradient	4.70	0.07	0.07	0.50	−0.03	−0.45
Technology maturity	6.99	0.61	0.31	−0.86	−0.28	−0.37
Plant complexity	6.18	−0.04	0.53	0.49	0.59	−1.43
Integration simplicity	6.78	0.05	0.42	−0.38	0.50	−0.78
Land use	4.82	0.12	0.55	0.52	0.14	−1.28
Cleaning water consumption	5.19	−0.76	0.68	−0.59	1.33	−0.69
Criteria groups						
Feasibility	6.92	−0.25	0.08	−0.25	0.23	0.17
Risk reduction	6.93	0.27	0.27	−0.53	0.26	−0.56
Impact reduction	4.92	−0.28	0.62	−0.58	0.99	−0.92
LCOE	7.98	0.45	−0.12	0.02	0.40	−0.78

Table 2
Average score of rating criteria for the 10 MW_e biomass/waste scenario and score difference for the 200 MW_e CCGT and 500 MW_e coal plants.

Criteria	10 MW_e	Δ200 MW_e	Δ500 MW_e
Peak solar to electricity efficiency	6.28	0.27	0.45
Suitable operation range	6.60	0.40	0.35
Maximum site gradient	4.45	0.27	0.48
Technology maturity	6.33	0.90	1.10
Plant complexity	6.33	−0.35	−0.10
Integration simplicity	6.98	−0.27	−0.30
Land use	4.88	−0.03	−0.15
Cleaning water consumption	5.30	−0.18	−0.15
Criteria groups			
Feasibility	6.80	0.13	0.23
Risk reduction	6.73	0.13	0.50
Impact reduction	4.90	0.05	0.00
LCOE	7.95	0.08	0.02

To cover the variety of aspects of a power project we invited people with different perspectives. They included plant operators, technology provider/EPC contractors, consultants and researchers, participant breakdown see Fig. 3. The operators included companies owning fossil and renewable energy assets, the technology provider comprised companies offering all of the CSP technologies assessed, see Section 3, and the consultants as well as researchers selected had a power generation background. All participants had years and many decades of experience in the energy business and represented well known national as well as international companies.

Due to the varying interest of the workshop participants/interviewees differences were observed in their criteria rating, see Table 1. Generally, operators (ΔO), consultants (ΔC) and researchers (ΔR) ranked the LCOE more important than the technology provider (ΔTP). Feasibility, risk and impact reduction were considered more important by technology providers and researchers while consultants ranked these criteria below average. Operators rated risk reduction above average and feasibility as well as impact reduction below average.

Similarly, rating differences were observed for the different CSP/host plant scenarios, see Table 2. The importance of a number of criteria increases with larger plant sizes, e.g. peak solar to electricity efficiency, technology maturity and suitable operation range. Interestingly, while participants rated all criteria groups getting more important with increasing plant sizes they considered half of the sub-criteria less relevant at larger scale, e.g. land use, water consumption and plant complexity.

As expected some sub-criteria were considered less important with increasing plant sizes, e.g. land use and integration simplicity. The reason for land use is that larger plants tend to be more remote than smaller facilities where land prices are typically significantly lower. At larger scale integration simplicity is less relevant as Economy-of-Scale benefits allow the installation of additional equipment. Interestingly, the cleaning water consumption for larger CSP installations was considered slightly less relevant. This was unexpected as usually water is scarcer in remote locations.

3. CSP technology selection

A precondition to obtain hybridization synergies is the ability of the CSP technologies to either directly or indirectly generate steam

Table 3
Parabolic trough data for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

Criteria	Unit	Parabolic trough		
High pressure CSP steam to CCGT plant		Molten salt	Synthetic oil	Water-steam
Peak solar to electricity conversion efficiency	%	26.7 [32]	21.0 [33]	22.6[a]
Suitable operation range	MW_{th}	12 [30]	80 [2]	34.2[a]
Maximum site gradient	Degrees	1 [24]	1 [24]	1 [24]
Technology maturity	Largest plant with financial approval, MW_e	5.0 [30]	140.0 [28]	9.0 [29]
Plant complexity	System cycles	2	2	1
Integration simplicity into water-steam system	Steam temperature of hybrid plant in °C	535 [30]	380 [34]	400 [35]
Land use	m^2/MWh/a	6[a]	8 [36]	7[a]
Cleaning water consumption	litre/MWhe	60[a]	75 [37]	70[a]
LCOE	US$/MWh	199[a]	232[b] [4]	202[a]

[a] Calculation by Juergen Peterseim based on information derived from literature and personal communication.
[b] Data from references modified to accommodate inflation and adjusted to 2011 US$ exchange rate.

Table 4
Solar tower data for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

Criteria	Unit	Solar tower				
High pressure CSP steam to CCGT		Molten salt	Water-steam	Air	Syngas	Gas turbine
Peak solar to electricity conversion efficiency	%	27.3[a]	28.7 [47]	31.5[a]	55.0[a]	47.5 [8]
Suitable operation range	MW_{th}	80 [40]	80 [47]	3 [41]	0.4 [42]	1.2 [48]
Maximum site gradient	Degrees	12 [16]	12 [16]	12 [16]	12 [16]	12 [16]
Technology maturity	Largest plant with financial approval, MW_e	110 [45]	130.0 [47]	1.5 [41]	0.3 [42]	0.25 [49]
Plant complexity	System cycles	2	1	2	1	2
Integration simplicity into water-steam system	Steam temperature of hybrid plant in °C	540[a]	565 [47]	565 [49]	565[b]	565[b]
Land use	m^2/MWh/a	12 [36]	11[a]	8[a]	6[a]	7[a]
Cleaning water consumption	litre/MWhe	114[a]	108[a]	98[a]	55[a]	64[a]
LCOE	US$/MWh	235[c] [4]	229[a]	359[c] [50]	126[a]	146[c] [49]

[a] Calculation by Juergen Peterseim based on information derived from literature and personal communication.
[b] Solarized gas turbine exhaust would allow the same Rankine cycle steam parameter as conventional gas turbines.
[c] Data from references modified to accommodate inflation and adjusted to 2011 US$ exchange rate.

Table 5
Fresnel data for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

Criteria	Unit	Fresnel	
High pressure CSP steam to CCGT		Saturated steam	Superheated steam
Peak solar to electricity conversion efficiency	%	16.9[a]	24.0[a]
Suitable operation range	MW_{th}	80 [6]	80 [12]
Maximum site gradient	Degrees	3 [25]	3 [25]
Technology maturity	Largest plant with financial approval, MW_e	30.0 [6]	125.0 [53]
Plant complexity	System cycles	1	1
Integration simplicity into water-steam system	Steam temperature of hybrid plant in °C	270 [6]	450 [52]
Land use	m^2/MWh/a	6 [36]	4[a]
Cleaning water consumption	litre/MWhe	15 [26]	10[a]
LCOE	US$/MWh	279[a]	237[b] [54]

[a] Calculation by Juergen Peterseim based on information derived from literature and personal communication.
[b] Data from references modified to accommodate inflation and adjusted to 2011 US$ exchange rate.

for the host plants Rankine cycle. That's why this study disregards PV, non-concentrating solar power as well as Dish-Stirling configurations. All data given should be considered relevant for the year 2011 with ±10% sensitivity. Results may change over the next years with new CSP systems maturing quickly and proving its expectations.

Low- and high-temperature integration options are assessed considering line and point focussing systems, including parabolic trough, Fresnel, solar tower and big dish. Depending on the CSP technology different working fluids, ranging from thermal oil, water-steam, molten salts, hot air and syngas, are considered.

In total 9 different technology options are compared for host plants using non-conventional fuels and coal. For combined cycle gas turbine (CCGT) plants two additional options are included in the technology comparison.

Most information derive directly from the literature and but some data were calculated using different literature sources, e.g. using the LCOE of US$232/MWh for parabolic troughs with thermal oil and applying a 14.2% LCOE cost reduction for molten salt [23]. Similarly, the land use of molten salt and DSG parabolic troughs derives from published data for parabolic trough plants with thermal oil and applying the different plant efficiencies, see Table 3. Other data derive from personal communication with industry experts, e.g. maximum site gradient for parabolic trough [24] and Fresnel systems [25] or cleaning water consumption for Fresnel plants [26].

3.1. Parabolic trough

Parabolic troughs using thermal oil are the most mature of all CSP technologies, with around 1.8 GW capacity installed worldwide. This reflects a 94% CSP market share [27]. Operating plants include the 354°MW_e SEGS I-IX, US and 3 × 50 MW_e Andasol, Spain facilities. Most of the units currently under construction use Parabolic troughs with thermal oil typically ranging from 50 MW_e, for example Extremadura Solar Complex, Spain, up to 280 MW_e units, e.g. 2 × 140 MW_e Solana project, US [28].

However, thermal oil degradation limits steam temperatures to around 380 °C, which poses a barrier to raise efficiencies. For this reason direct steam generation (DSG) as well as molten salts are being investigated with small-scale plants currently being erected. The efficiency of such systems could be significantly higher due to steam parameters well above 450 °C and 100 bar. Higher plant efficiencies also reduce the solar field size and therewith cleaning water consumption as well as land use. The largest DSG plant in operation is the 9 MW_e Suphanaburi project in Thailand [29] while a 5 MW_e molten salt plant is built in Priolo Gargallo, Italy [30]. Currently, both technologies are significantly less mature than thermal oil in parabolic troughs but higher efficiency and lower LCOE prospects make them attractive alternatives for future projects.

Integrated Solar Combined Cycle plants using parabolic troughs are already in operation, e.g. the 75 MW_e equivalent CSP contribution to the FPL Next Generation plant, US [11] or the 22 MW_e equivalent CSP contribution to the Kuraymat plant, Egypt [7]. Also feedwater heating has been tested in the Cameo coal fired power station, US [31].

Table 3 shows the data used in the workshop to compare the different parabolic trough technologies for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant [23].

3.2. Solar tower

Currently, solar towers represent only ~4% of CSP plants in Spain [27]. This low percentage increases risk driven financing costs. However, a few units with DSG, such as the 5 MW_e Sierra

Table 6
Dish data for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

Criteria	Unit	Big dish
High pressure CSP steam to CCGT		Water-steam
Peak solar to electricity conversion efficiency	%	27.0 [59]
Suitable operation range	MW_{th}	18[b]
Maximum site gradient	Degrees	12 [16]
Technology maturity	Largest plant with financial approval, MW_e	4.9 [60]
Plant complexity	System cycles	1
Integration simplicity into water-steam system	Steam temperature of hybrid plant in °C	565 [56]
Land use	m^2/MWh/a	12 [36]
Cleaning water consumption	litre/MWhe	114[b]
LCOE	US$/MWh	252[a] [61]

[a] Calculation by Juergen Peterseim based on information derived from literature and personal communication.
[b] Data from references modified to accommodate inflation and adjusted to 2011 US$ exchange rate.

Criteria	Importance (1-9)	Criteria groups	Importance (1-9)
Solar to electricity efficiency		Feasibility	
Suitable operation range			
Maximum site gradient			
Technology maturity		Risk reduction	
Plant complexity			
Integration simplicity			
Land use		Impact reduction	
Total water consumption			
		LCOE	

Participant: ____________________

Assumptions:

- 10MWe solid fuel power plant
  - a) 30MWth Clean Biomass 480°C @ 100bar
  - b) 35MWth C&D Timber 450°C @ 80bar
  - c) 38MWth RDF 430°C @ 60bar
  - d) 40MWth MSW 400°C @ 40bar
  - e) Steam reheating 300°C @ 26bar
  - f) Feedwater preheating 270°C @ 40bar
- 20MWth additional CSP contribution

Criteria	Unit	Parabolic Trough			Solar Tower			Fresnel		Dish
a) Clean Biomass		Molten Salt	Synthetic Oil	Water-Steam	Molten Salt	Water-Steam	Air	Saturated Steam	Superheated steam	Water-Steam
Peak solar to electricity conversion efficiency	%	26.7	21.0	22.6	27.3	28.7	31.5	16.9	24.4	27.0
Suitable operation range	MWth	12	20	20	20	20	3	20	20	18
Maximum site gradient	Degrees	1	1	1	12	12	12	3	3	12
Technology maturity	Largest plant with financial approval, MWe	5.0	140.0	9.0	110.0	130.0	1.5	30.0	125.0	4.9
Plant complexity	System cycles	2	2	1	2	1	2	1	1	1
Integration simplicity into water-steam system	Steam temperature of hybrid plant in °C	480	380	400	480	480	480	270	450	480
Land use	m2/MWh/a	6	8	7	12	11	10	6	4	12
Cleaning water consumption	litre/MWhe	60	76	70	114	108	98	15	10	114
LCOE	$/MWh	199	232	202	235	229	359	279	237	252

Criteria	Unit	Parabolic Trough			Solar Tower			Fresnel		Dish
Integration simplicity into water-steam system		Molten Salt	Synthetic Oil	Water-Steam	Molten Salt	Water-Steam	Air	Saturated Steam	Superheated steam	Water-Steam
b) Construction & Demolition Timber	Steam temperature of hybrid plant in °C	450	380	400	450	450	450	270	450	450
c) Refuse Derived Fuel	Steam temperature of hybrid plant in °C	430	380	400	430	430	430	270	430	430
d) Municipal Solid Waste	Steam temperature of hybrid plant in °C	400	380	400	400	400	400	270	400	400
e) Steam reheating	Steam temperature of hybrid plant in °C	300	300	300	300	300	300	270	300	300
f) Feedwater heating	Steam temperature of hybrid plant in °C	270	270	270	270	270	270	270	270	270

Fig. 2. Participant's form for CSP integration into a biomass/waste to energy host plant.

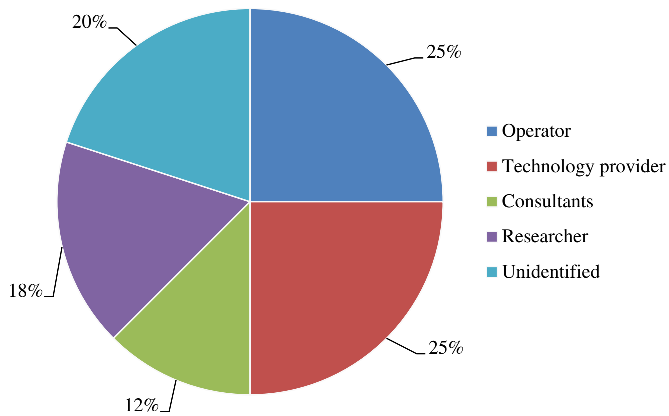

Fig. 3. Percentages of people rating the CSP integration scenarios.

SunTower in the US [38], the 11 MW_e PS10 and 20 MW_e PS20 plants in Spain [39], and molten salt, for example 20 MW_e Gemasolar in Spain [40], are already in operation. Significantly smaller tower systems generating high temperature air for Brayton or Rankine cycles, such as the 1.5 MW_e Solair project in Germany [41], and syngas for gas turbine applications, such as the 300 kW_e SOLASYS project in Israel [42], are tested but currently far from commercial reality due to its small scale. However, these systems have the potential to significantly reduce the LCOE of CSP in the future.

The capacity of current solar tower installations does not exceed 20 MW_e, even though the 120 MW_{th} capacity of the Gemasolar receiver could power a larger turbine but instead charges a maximum 15 h full-load thermal storage [40]. However, significantly larger plants are under construction, for example 3 × DSG solar towers totalling 392 MW_e at Ivanpah [43], and the 110 MW_e Crescent Dunes project in the US using molten salt [44,45]. Once these plants come online and prove their technical and commercial expectations the solar tower technology is very likely to gain a significantly bigger CSP market share. Currently, there are no solar tower hybrid plants in operation worldwide despite the concept being investigated [46].

The efficiency differences for the selected tower technologies results in significantly different values for cleaning water and land use as well as LCOE. Syngas and gas/hot air turbine concepts have the highest reduction potential due to the high efficiency potential of combined cycle systems.

Table 4 shows the data used in the workshop to compare the different solar tower technologies for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant. Solar tower options to provide high temperature air for hot air/gas turbine operation as well as syngas generation were only considered for the CCGT scenarios.

3.3. *Fresnel*

Similar to solar towers Fresnel is a CSP technology that's currently in the stage of proving its commercial viability with commercial plants being under construction. Currently, only ~2% of the CSP plants in Spain use this technology [27]. Suppliers offer Fresnel plants generating saturated steam, such as the 1.4 MW_e and 30 MW_e Puerto Errado plants in Spain [6], and superheated steam, e.g. 5 MW_e Kimberlina plant in the US, 44 MW_e Kogan Creek Solar Boost in Australia and 250 MW_e (2 × 125 MW_e) Reliance project in India [51]. Fresnel plants are commercially available for steam temperatures of up to 450 °C [52].

The simplicity of the Fresnel system raises expectations for cost reductions but the technology has the disadvantage that thermal storage is not commercially available yet. However, the current lack of monetary value for energy dispatchability, as seen by the conversion of CSP projects to PV [1], does not require thermal storage for a commercially viable project, as demonstrated by the 250 MW_e Reliance project in India [53]. Currently, large/smart electricity networks have the ability to absorb the limited outputs of CSP plants and higher daytime demand coincides with CSP plant operation.

Fresnel plants are already retrofitted to coal fired power stations for feedwater heating, for example at Liddell in Australia [6], and under construction to provide steam into the cold reheat line, e.g. Kogan Creek power station in Australia and Sundt power station in the US [51].

The efficiency of Fresnel systems can vary significantly with saturated steam systems having inherently low cycle efficiencies compared to the latest Fresnel demonstration projects reaching 500 °C [52]. The higher efficiencies impact LCOE as well as land use and cleaning water consumption. It is worth mentioning that Fresnel systems have the lowest cleaning water requirements of all CSP technologies due to robotic cleaning of the flat mirror panels.

Table 5 shows the data used in the workshop to compare the different Fresnel technologies for integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

3.4. *Big dish technology*

Predominantly, paraboloidal dishes are used in conjunction with Stirling engines. As this concept does not offer relevant synergies only dish concepts using water-steam are considered. The big dish technology developed by the Australian National University (ANU) [55] fulfils this criterion, demonstrated steam temperatures of 580 °C [56] and is therefore considered in this assessment.

Despite having the highest concentration ratio and the potential for excellent conversion efficiencies [57] big dish systems do not play a relevant role in new CSP construction projects currently. The reasons for the small uptake are likely to be the very limited number of reference plants worldwide as well as high costs associated with premature technologies. At the ANU a 500 m^2 big dish is currently being tested and the only multi MW_e standalone project under development with a substantial government grant is the 40 MW_e SolarOasis project in South Australia [58].

With the high steam parameters demonstrated, accurate solar tracking and high concentration ratios the annual efficiency potential of these systems is high but the comparatively small thermal capacity of each big dish requires an extensive high temperature/pressure piping system with associated thermal losses. A pre-commercial plant, around 5 MW_e, would be required to demonstrate the benefits and test the concept in a commercial environment. The land use of this technology is high compared to line-focussing systems, but in line with molten salt and DSG solar towers, as the dishes have to be spaced out to avoid shading.

Table 6 shows the big dish data used in the workshop for the integration of 80 MW_{th} from CSP into a 200 MW_e CCGT power plant.

4. Host plant scenarios

The host plant scenarios considered cover all relevant fuels, biomass, waste materials, natural gas and coal, as well as several steam integration options, e.g. feedwater heating, cold reheat line, steam boost and superheated steam to the steam turbine's high pressure stage, see Fig. 4. The CCGT scenario has two additional options, syngas and high temperature air for gas/hot air turbines.

Analysing the different conversion technologies for solid fuels, such as combustion or gasification, and gaseous fuels, such as different gas turbine types, is not part of this study and not relevant as only the steam parameters of any given steam generator are of relevance for the integration of the CSP technology.

Depending on fuel and location the CSP field can act as a fuel saver or power top-up to the host plant. Maximizing the equipment usage is desirable to recover the capital spent as quickly as possible. For this reason the ideal scenario for new plants, using low/no emission fuels, is a power top-up while retrofits are likely to be fuel saver applications substituting expensive/CO_2 intensive fuels.

4.1. Non-conventional fuel fired power plants

In this assessment non-conventional fuels include biomass as well as waste materials. The fuels considered are clean biomass, construction & demolition (C&D) timber, refuse derived fuel (RDF) as well as municipal solid waste (MSW). With falling fuel qualities the superheated steam temperature decrease due to high-temperature corrosion inside the boiler and other technical issues, see Table 7. Steam reheating and feedwater heating is considered for all fuels and all scenarios assuming a 10 MW_e power plant with a 20 MW_{th} CSP contribution.

As seen in Table 7 not all CSP technologies can achieve the steam temperatures required by the different host plants. CSP technologies that cannot produce the desired steam temperature are excluded from the assessment.

The hybridisation of CSP with non-conventional fuels is likely to be a niche market, compared to natural gas, but allows CSP plants to transition from arid desert/semi desert regions to agricultural/urban regions. Being closer to load centres reduces transmission losses, can avoid/defer new transmission infrastructure and enables the access to back-up fuel resources, e.g. agricultural and urban waste materials. Using biomass and waste materials does allow, subject to waste material composition, renewable base-load power generation.

Table 7
Suitability of CSP technologies to reach the required steam temperatures for 10 MW_e non-conventional fuel fired power plants.

Temperature required	Clean biomass, 480 °C	C&D timber, 450 °C	RDF, 430 °C	MSW, 400 °C	Steam reheating, 300 °C	Feedwater heating, 270 °C
Parabolic trough						
Molten salt	Yes	Yes	Yes	Yes	Yes[a]	Yes[a]
Synthetic oil	No	No	No	No	Yes	Yes
Water-steam	No	No	No	Yes	Yes	Yes
Solar tower						
Molten salt	Yes	Yes	Yes	Yes	Yes[a]	Yes[a]
Water-steam	Yes	Yes	Yes	Yes	Yes[a]	Yes[a]
Air	Yes	Yes	Yes	Yes	Yes[a]	Yes[a]
Fresnel						
Saturated steam	No	No	No	No	No	Yes
Superheated steam	No	Yes	Yes	Yes	Yes	Yes[a]
Big dish						
Water-steam	Yes	Yes	Yes	Yes	Yes[a]	Yes[a]

[a] Can realise the steam temperature required but is not considered in assessment as systems are not designed for low steam temperature applications.

4.2. Combined cycle gas turbine plants

Principally, the CSP technologies considered in this section are the same as in Sections 4.1 and 4.3 except that CCGT plants can be hybridized with two additional CSP technologies, solar towers providing hot air [48] and syngas [42]. Different to the other CSP technologies these two technologies have a significantly higher efficiency potential, see Table 4, as they can be used in the toping cycle of the CCGT plant and the bottoming Rankine cycle.

The integration of CSP at different steam temperatures is assessed including steam reheating and feedwater heating, see Table 8. The assumed host plant is a 200 MW_e CCGT unit with a 80 MW_{th} CSP contribution for each scenario.

Integrated solar combined cycle (ISCC) plants have significant potential to further reduce CO_2 emissions from natural gas

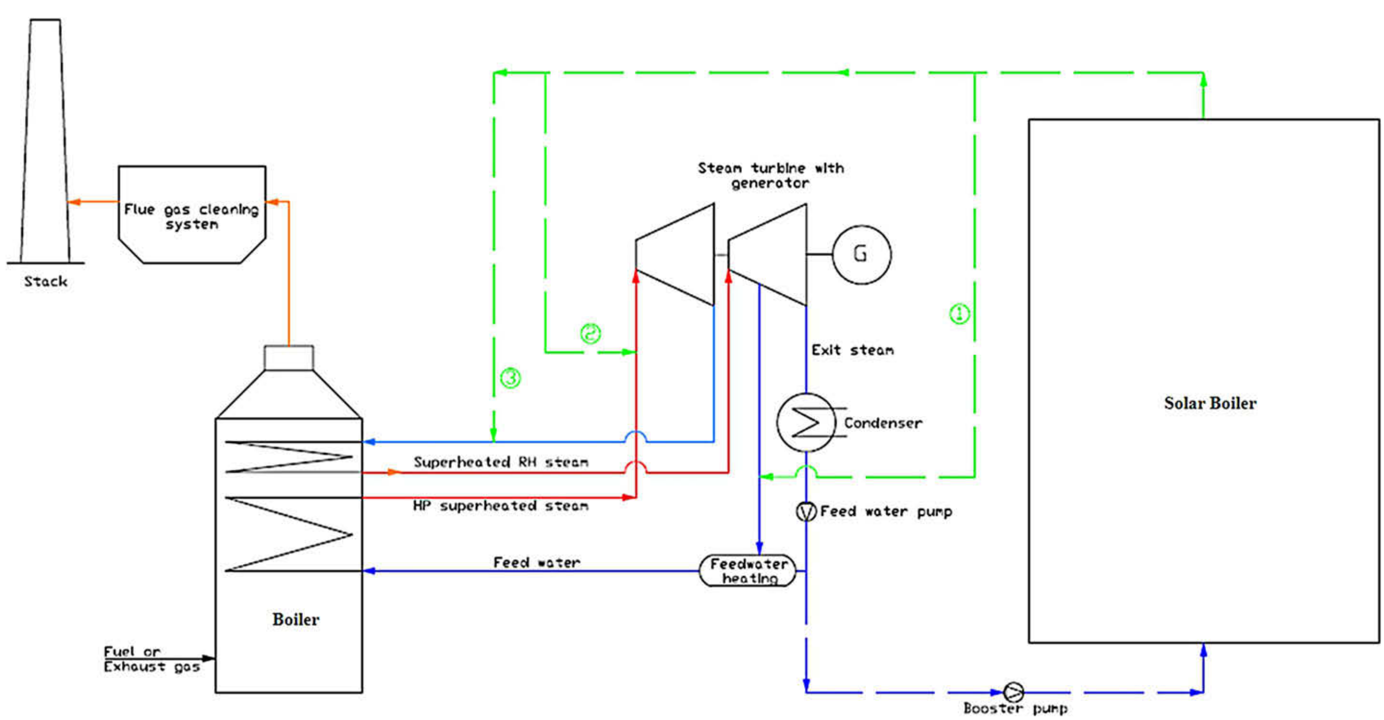

Fig. 4. Simplified schematic of CSP integration options into host plants; 1) feedwater heating; 2) high-pressure steam; 3) cold reheat line/steam boost.

combustion as many OCGT & CCGT plants operate in high DNI areas, such as Australia, Africa, India, Arabian Peninsula or the US.

4.3. Coal fired power station

Depending on the construction year of coal fired power stations different steam temperatures and pressure apply. While the majority of the older coal fired power plants operate around 540 °C and 160 bar steam, newer installations operate with 580 °C, supercritical or ultra-supercritical conditions. Currently, no CSP technology demonstrated supercritical steam at pilot plant scale and we therefore chose 580 °C, demonstrated by the big dish technology in Australia [56], as the highest steam temperature in this assessment. The other steam temperature scenarios chosen and the ability of the CSP technologies to meet them are listed in Table 9. The assumed coal plant to be retrofitted with 150 MW_{th} from CSP is a 500 MW_e unit.

The retrofit of CO_2 intensive coal fired power station is one promising option to reduce the carbon footprint of these plants for their remaining lifetime. However, the addition of a CSP steam generator should not be used as a justification to extend the originally predicted operational life of old assets or delay the investment in low emission/renewable energy plants. Such behaviour can easily offset the CO_2 emissions avoided by the CSP add-on. Hence careful consideration has to be given to CSP retrofit proposals.

Table 9
Suitability of CSP technologies to reach the required steam temperatures for a 500 MW_e coal fired plant.

Temperature required	HP steam I, 580 °C	HP steam II, 540 °C	Steam reheating, 360 °C	Feedwater heating, 270 °C
Parabolic trough				
Molten salt	No	No	Yes[a]	Yes[a]
Synthetic oil	No	No	Yes	Yes
Water-steam	No	No	Yes	Yes
Solar tower				
Molten salt	No	Yes	Yes[a]	Yes[a]
Water-steam	No	Yes	Yes[a]	Yes[a]
Air	Yes	Yes	Yes[a]	Yes[a]
Fresnel				
Saturated steam	No	No	No	Yes
Superheated steam	No	No	Yes	Yes[a]
Big dish				
Water-steam	Yes	Yes	Yes[a]	Yes[a]

[a] Can realise the steam temperature required but is not considered in assessment as systems are not designed for low steam temperature applications.

5. Technology ranking results

The technology ranking in this assessment is based on the criteria rating by the workshop participants/interviewees as well as the data identified for the different CSP technologies. Most CSP data used in the assessment remain unchanged for the different integration options except for the steam temperature and the CSP reference plants (20 MW_{th}, 80 MW_{th} and 150 MW_{th}).

5.1. Energy from non-conventional fuel fired power plants

For the integration of a CSP system into a host plant using clean biomass and generating steam at 480 °C the DSG solar tower scores best, see Fig. 5. The molten salt solar tower technology ranks second and is well within the 10% sensitivity margin. The big dish technology ranks third but is just outside the DSG solar tower sensitivity margin. Only 5 of the 9 CSP technologies are able to reach the steam temperature required and the DSG solar tower scores best because of the good reference situation in this plant size and a higher permissible site gradient.

Host plants using C&D timber, RDF and MSW ideally use Fresnel steam generators to provide superheated steam at 400–450 °C to the joint turbine, see Fig. 5. The reasons for the very high score include the low cleaning water requirements through robotic cleaning of the flat mirror panels, the strong reference situation and the compact solar field minimizing land use. The DSG solar tower ranks second followed by the molten salt solar tower technology. However, their scores are significantly lower and outside the ±10% Fresnel sensitivity margin. Several other CSP technologies qualify for these host plant scenarios but their total scores are even lower.

Fresnel with superheated steam also scores best for cold reheat steam followed by parabolic trough systems using thermal oil. For solar feedwater heating applications Fresnel with saturated steam ranks best but is closely followed by parabolic troughs using thermal oil. DSG parabolic trough systems rank third and all three technologies are within the ±10% sensitivity margin.

Currently, the only CSP/biomass hybrid plant under construction is the 22.5 MW_e Termosolar Borges project, Spain [62]. The plant is using parabolic troughs with thermal oil providing 375 °C steam to the turbine [63]. Using this temperature in our assessment Fresnel would have been the chosen option followed by parabolic trough with thermal oil. The maturity of the parabolic trough technology is a significant contributor to its total score but Fresnel

Table 8
Suitability of CSP technologies to reach the required steam temperatures for a 200 MW_e CCGT plant.

Temperature required	HP steam, 565 °C	High temperature steam boost, 450 °C	Low temperature steam boost, 350 °C	Steam reheating, 300 °C	Feedwater heating, 260 °C
Parabolic trough					
Molten salt	No	Yes	Yes[a]	Yes[a]	Yes[a]
Synthetic oil	No	No	Yes	Yes	Yes
Water-steam	No	No	Yes	Yes	Yes
Solar tower					
Molten salt	No	Yes	Yes[a]	Yes[a]	Yes[a]
Water-steam	Yes	Yes	Yes[a]	Yes[a]	Yes[a]
Air	Yes	Yes	Yes[a]	Yes[a]	Yes[a]
Syngas	Yes	Yes[b]	Yes[b]	Yes[b]	Yes[b]
Air to air/gas turbine	Yes	Yes[b]	Yes[b]	Yes[b]	Yes[b]
Fresnel					
Saturated steam	No	No	No	No	Yes
Superheated steam	No	Yes	Yes	Yes	Yes[a]
Big dish					
Water-steam	Yes	Yes	Yes[a]	Yes[a]	Yes[a]

[a] Can realise the steam temperature required but is not considered in assessment as systems are not designed for low steam temperature applications.
[b] Technologies developed to be used in a gas/hot air turbine only.

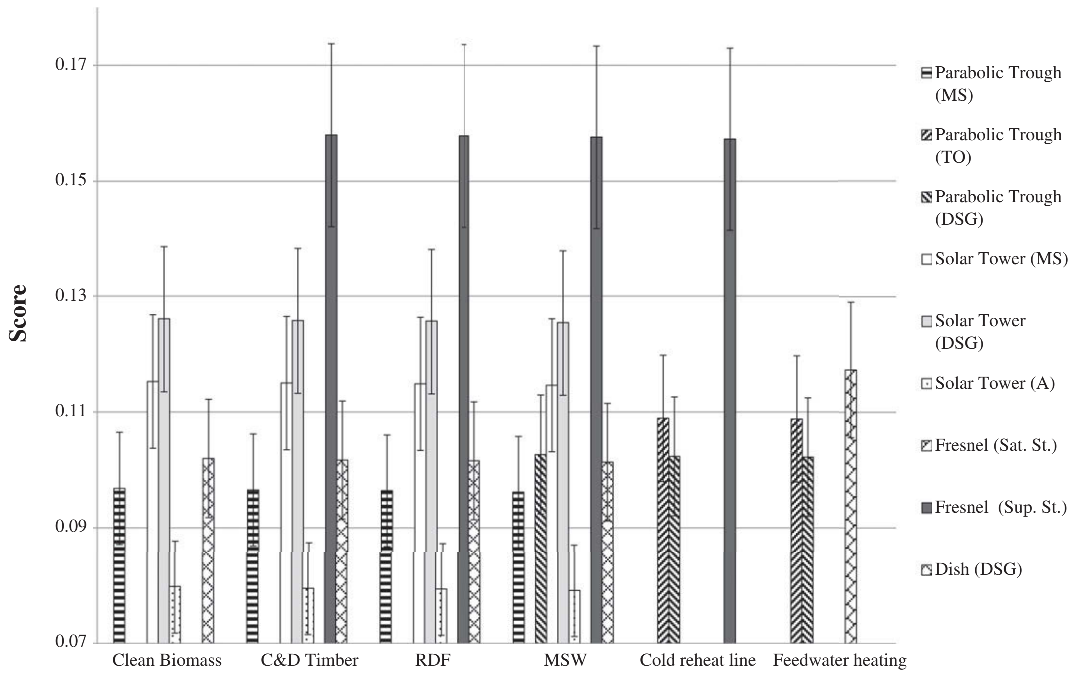

Fig. 5. CSP technology ranking results for the hybridisation with 10 MW_e non-conventional fuels.

scores better because of its decent reference situation in the ≤20 MW_{th} scale and additional benefits, such as low land and cleaning water use. The poorer Fresnel reference situation during the planning period of the project and the better bankability of parabolic trough (thermal oil) is likely to have given it a competitive edge in the Termosolar Borges decision making process, considering that this is the first CSP/biomass hybrid plant worldwide and risk mitigation was probably a key criterion. It needs to be mentioned that the steam temperature from the biomass used in the Termosolar Borges project could be at least 50 °C higher, without high-temperature corrosion problems inside the biomass boiler, when choosing a Fresnel or solar tower system.

Currently, there are no CSP hybrid plants under construction using C&D timber, RDF or MSW.

5.2. Combined cycle gas turbine plants

For integrating a 565 °C steam source into the high pressure Rankine cycle of a 200 MW_e CCGT plant the DSG solar tower seems the preferred option, see Fig. 6, very closely followed by the syngas solar tower. Despite limited references the syngas solar tower scores well due to the highly efficient syngas use in the gas turbine and associated low LCOE prospects. However, financing a commercial scale plant is likely to be challenging because of limited

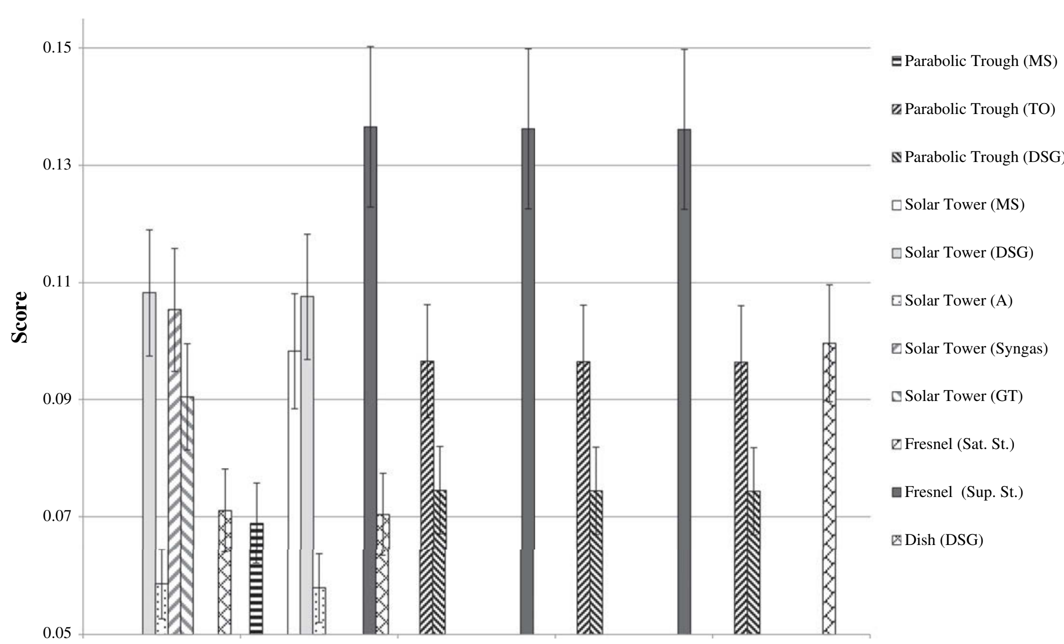

Fig. 6. CSP technology ranking results for the hybridisation with a 200 MW_e CCGT plant.

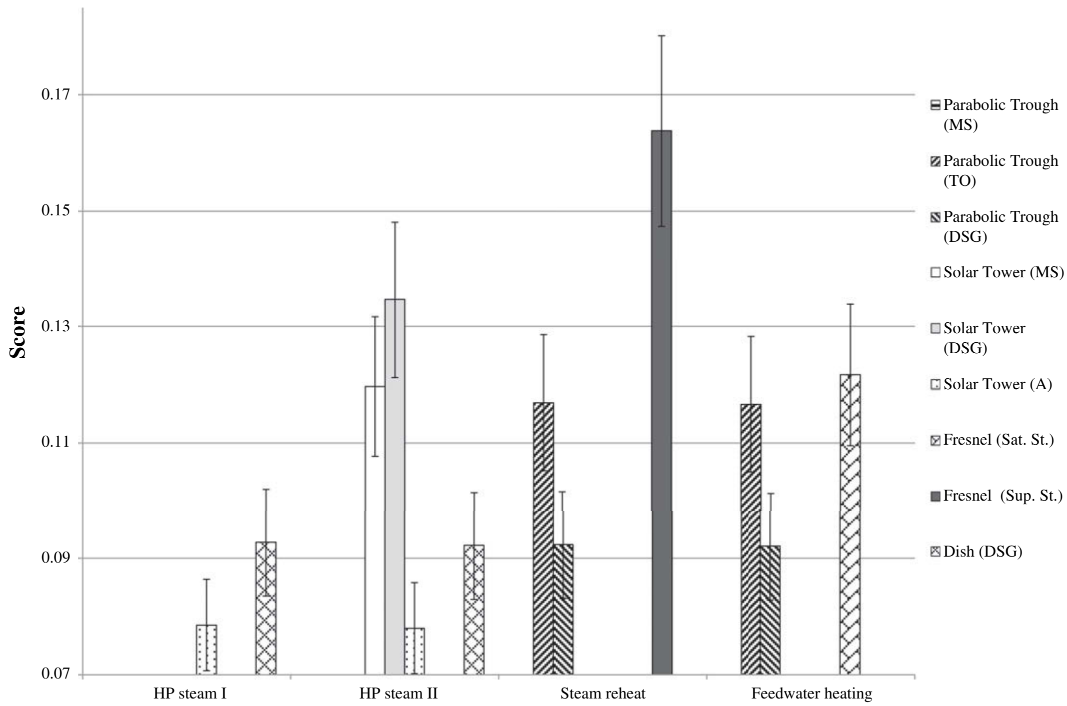

Fig. 7. CSP technology ranking results for the hybridisation with a 500 MW_e coal fired power plant.

references. The DSG solar tower scores slightly better due to the strong reference situation and technology maturity which simplifies project finance at this point in time. The solar tower providing hot air to a solarised GT ranks third because of its high efficiency and low LCOE potential. All three technologies are within the ±10% sensitivity margin.

For the high temperature steam boost at 450 °C Fresnel (superheated steam) qualifies as a viable option and scored best, due to its reference situation combined with low cleaning water and land use. DSG solar towers rank second with molten salt solar towers third, see Fig. 6. However, both technologies are outside Fresnel's ±10% sensitivity margin.

At steam temperatures <380 °C, as in the low temperature steam boost and cold reheat scenarios, Fresnel (superheated steam) ranks best due to the good reference situation and low water/land use. Parabolic trough (thermal oil) is second and DSG parabolic troughs rank third but with significantly lower scores outside Fresnel's ±10% sensitivity margin, see Fig. 6. Point focussing systems are not considered as they are designed to provide steam at temperatures >400 °C. For the 260 °C feedwater heating scenario Fresnel generating saturated steam score best closely followed by parabolic troughs with thermal oil. Fresnel with superheated steam is not considered an appropriate technology for such low steam temperatures.

To subject the assessment process to reality we used the CSP technology chosen for the ISCC plant Kuraymat, Egypt. Through thermal oil a parabolic trough field provides saturated steam at 95 bar to the high pressure drum of the heat recovery steam generator [64]. At 95 bar the saturated steam temperature is 307 °C. Using this data in our assessment Fresnel would have been the chosen technology followed by parabolic trough. Using the very limited Fresnel reference situation from 2001 in this assessment, Kuraymat planning commenced this year, results in parabolic trough with thermal oil being the preferred CSP choice. The latest hybrid project at the dual-fuel (coal and gas) Sundt power station in the US is using Fresnel as the steam boost technology [51]. This demonstrates the ongoing changes in the CSP industry caused by quickly maturing new technologies.

5.3. *Coal fired power station*

Feeding steam at 580 °C into the high pressure steam turbine of a coal fired power plant is only possible with 2 of the 9 CSP technologies assessed, big dish and solar tower (hot air). The big dish is the preferred technology for this scenario because of its slightly better reference situation, lower plant complexity and lower LCOE, see Fig. 7. The total score of both technologies is comparatively low as the reference situation is very limited, maturity low and hence LCOE higher than for other technologies.

For providing steam at 540 °C, HP steam II scenario, the solar towers with DSG and molten salt qualify for the assessment and score best because of the better reference situation, higher maturity and lower LCOE than the big dish and hot air solar tower. The DSG technology ranks better than molten salt due to the simpler integration but both technologies are within the ±10% sensitivity margin, see Fig. 7.

The steam reheat and feedwater heating results look very similar to the CCGT results in Fig. 6. Steam temperatures are similar and only the sub-criterion for suitable operation range changes the total scores slightly, see Fig. 7.

At the 750 MW_e Kogan Creek power station in Australia a Fresnel plant providing superheated steam to the cold reheat line is currently under construction [12]. According to our assessment the preferred CSP technology to provide 370 °C steam would have been Fresnel with superheated steam too. Kogan Creek power station is an air cooled unit which indicates water scarcity in the area. The low cleaning water consumption as well as land use are likely reasons for the Fresnel selection. Similarly the results are in line with the recent solar feedwater heating project at Liddell power station in Australia which uses Fresnel with saturated steam [6].

6. Conclusions

The hybridisation of CSP steam generators with different Rankine cycle host plants was assessed in this paper using the Analytical Hierarchy Process with quantitative and qualitative data inputs and the results are in line with the hybrid plants in operation/under construction worldwide.

According to this assessment line focussing systems seem to be the ideal choice for lower temperature steam integration (<400 °C), with Fresnel and parabolic trough (thermal oil) being the most relevant. In the >380 to <450 °C steam integration range Fresnel systems score best. While the parabolic trough technology scores well, because of technology maturity, Fresnel scores well at land use and cleaning water consumption.

The high temperature steam integration of CSP (>450 °C) favours point focussing systems with DSG solar towers scoring best. In 2011 they had the best reference situation of all point focussing technologies considered and operating expertise has existed for several years. Solar towers with molten salt are maturing quickly with the Gemasolar plant, Spain, in operation and larger facilities under construction. They are likely to be the favoured high steam temperature technology for CSP hybrid projects including thermal storage.

This assessment includes general characteristics but results are likely to alter slightly using site specific data, such as land availability or water scarcity. The attitude of investors to technology risk is a criterion that can change the ranking process significantly. The model presented can accommodate such site specific changes to provide appropriate guidance for CSP technology selection.

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4.4 Techno-economic optimisation

The following publications analyse different CSP–EfB and CSP–EfW hybridisation options in regards to their technical, economic and environmental performance. Various CSP, EfB and EfW technologies are considered to answer the following research questions:

- What are the best concepts for combining CSP with EfB and EfW systems?
- What are the cost differences between CSP–EfB and CSP–EfW hybrids and CSP-only plants in Australia?

Each publication investigates a different technical concept. The first one examines the generation of steam by CSP and EfB steam generators with identical parameters (Section 4.4.1) and the second one examines the use of biomass to externally superheat steam from a parabolic trough plant (Section 4.4.2). The first concept is suitable for areas with significant biomass or waste feedstock resources as the concept is based on the EfB/EfW component operating continually throughout the year while the CSP component provides valuable peak capacity during the day and, with TES, the evening and morning periods. The external superheating concept is designed to minimise solid feedstock consumption as it only requires a small energy input to raise the already high steam parameters from the parabolic trough plant. Therefore this concept is ideal for utility scale plants in higher DNI areas where biomass and waste feedstock availability declines as shown in Section 4.2. The concept is specifically designed to improve the economic viability of the currently dominant parabolic trough technology with thermal oil as its efficiencies are constrained by thermal oil degradation at temperatures above 400 °C. Other technologies, such as solar towers, do not need to use biomass or waste feedstocks to reach steam temperatures in excess of 500 °C and high pressures. The use of CSP for air and feedwater heating, as well as cold reheat steam, is not considered in the analyses as these options do not allow a significant solar share in hybrid plants.

4.4.1 Identical steam parameter from CSP and biomass components

This publication analyses various CSP, EfB, and EfW technology pairings for hybrid plants to identify the best ones in regards to their technical, economic and environmental performance.

In addition to the process diagram shown in Figure 2 in this paper, two additional process diagrams for scenarios 16 and 17 + 3 h TES can be found in the appendix.

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Hybridisation optimization of concentrating solar thermal and biomass power generation facilities

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Abstract

Recently, the first concentrating solar power–biomass hybrid power plant commenced operation in Spain and the combination of both energy sources is promising to lower plant investment. This assessment investigates 17 different concentrating solar power–biomass hybrid configurations in regards their technical, economic and environmental performance. The integration of molten salt thermal storage is considered for the best performing hybrid configuration. While thermal storage can increase plant output significantly even 7 h full-load thermal storage plants would generate the majority of the electricity, 70%, from the biomass resource.

Only mature technologies with references >5 MWe are considered in this assessment to ensure that the scenarios are bankable. The concentrating solar power technologies selected are parabolic trough, Fresnel and solar tower while the biomass systems include grate, fluidised bed and gasification with producer gas use in a boiler.

A case study approach based on the annual availability of 100,000 t of wood biomass is taken to compare the different plant configurations but the results are transferable to other locations when updating site and cost conditions. Results show that solar tower–biomass hybrids reach the highest net cycle efficiency, 32.9%, but that Fresnel-biomass hybrids have the lowest specific investment, AU$ 4.5 m/MWe. The investment difference between the 17 scenarios is with up to 31% significant. Based on the annual electricity generation CSP–biomass hybrids have an up to 69% lower investment compared to standalone concentrating solar power systems. The scenario with the best technical performance, being solar tower and gasification, is at this point in time not necessarily the best commercial choice, being Fresnel and fluidised bed, as the lower Fresnel investment outweighs the additional electricity generation potential solar towers offer. However, other scenarios with different benefits rank closely.

Keywords: Concentrating solar power–biomass hybrid plants; Energy from biomass; Parabolic trough; Fresnel; Solar tower

1. Introduction

Concentrating solar power (CSP)–biomass hybrid plants are a well accepted solution for comparatively low cost base-load/dispatchable renewable energy but are a niche market considering the limited areas with a sufficiently high direct normal irradiance, >1700 kW h/m^2/

Abbreviations: CSP, concentrating solar power; PPA, power purchase agreement; PT, parabolic trough; ST, solar tower; F, Fresnel; IRR, internal rate of return on investment; TO, thermal oil; DSG, direct steam generation; MS, molten salts; TS, thermal storage; DNI, direct normal irradiance; AU$, Australian Dollar (AU$/US$ = 0.96).

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year, and biomass resources. Countries such as Australia, Spain, Italy, Greece, Thailand, India, and Brazil are, amongst others, prime candidates for such projects as these countries have locations that meet both criteria. To maximize the commercial viability and efficient biomass use the power plant concepts should be as efficient as possible considering the economic realities of obtaining finance for such projects.

Recently, the first CSP–biomass hybrid plant commenced operation near Barcelona, Spain (Protermosolar, 2012), which proves that such concepts work technically and are bankable solutions. Despite other CSP–biomass configurations being investigated in the past, including Fresnel and tower systems, no other projects commenced construction at this point in time.

This paper investigates different possible CSP–biomass hybrid configurations with the aim of identifying the best in regards to technical, economic, and environmental performance, such as cycle efficiency, investment, and CO_2 abatement potential. The efficient use of biomass is not only necessary to maximize plant output, but also to optimize usage as biomass has to be purchased competitively against other users, such as pulp and paper industry. Understanding the different CSP–biomass hybrid options will enable project developers to concentrate on the most promising ones therewith increasing chances to successfully implement such projects.

All scenarios investigated in this paper assume that the biomass boiler is operating constantly at full capacity, that the CSP system provides additional capacity during the daytime when electricity demand/prices are typically higher in Australia (Lekovic et al., 2011), and that the CSP and biomass systems can operate independent of each other by providing identical steam flows/parameters to the joint turbine. To minimize plant investment molten salt thermal storage is considered only for one high temperature scenario as its cost are still comparatively high and the biomass component can generate electricity at lower cost during the night and extended cloud coverage. Future work could investigate CSP–biomass hybrids with thermal storage in more detail by considering other storage media, such as pressurized water or steam, and tank configurations, such as single tanks.

2. Current hybrid proposals

First proposals to combine CSP with biomass/waste materials using dish systems were investigated briefly in the 1980s (McDonald, 1986). However, due to technical and financial issues no plants were built. It took more than two decades before the first commercial CSP–biomass hybrid plant, Termosolar Borges 22.5 MWe (Morell, 2012), commenced operation near Lleida, ca. 150 km west of Barcelona, Spain, see Fig. 1. The plant is located further north than any other CSP project in Spain and uses the mature trough technology with thermal oil (Cot et al., 2010). The solar field generates saturated steam at 40 bar and the biomass boilers superheat this steam to 520 °C (Morell, 2012). The steam temperature is well selected to avoid high-temperature corrosion on the superheaters from this type of fuel, wood see Fig. 1. To further optimize the concept its steam pressure could be raised >40 bar (Morell, 2012).

Several other studies investigated the hybridisation of parabolic trough plants with biomass considering capacities from 2 MW_{th} to 107 MWe but no other project has yet commenced construction (Pérez and Torres, 2010; Schnatbaum, 2009; Nixon et al., 2010; California Energy Comission, 2008). These studies concentrate on integrating a biomass fired steam boiler into the CSP plant's water-steam cycle but also consider a biomass fired heater in the thermal oil or molten salt cycle.

Alternatively, Fresnel systems have been investigated for hybridisation with biomass and waste materials (Peterseim et al., 2012; Rojas et al., 2010; Spliethoff et al., 2010; Nixon et al., 2012). The benefit of using Fresnel would be steam temperatures up to 500 °C (Fluri et al., 2012) and subsequent higher conversion efficiencies. However, no reference plants yet exist for this CSP configuration.

Solar towers with direct steam generation (DSG) and molten salts are being investigated in combination with biomass (Peterseim et al., 2013) as are solar towers using a volumetric air receiver (Coelho et al., 2012). Due to the limited reference situation of high-temperature air tower systems and the higher complexity of such a system it is expected that solar towers with DSG or molten salts are easier to finance. Another option to combine high-temper-

Fig. 1. First CSP–biomass plant under construction near Lleida, Spain (left) and biomass fuel (right).

ature air systems with biomass is an integrated gasification combined cycle plant with the CSP component heating the gas turbine air downstream the compressor to 800 °C and syngas combustion to increase the temperature to 1150 °C, similar to SOLGATE project (ORMAT, 2005) but with biomass derived syngas rather than natural gas. The use of the gas turbine exhaust to operate a Rankine cycle would make such a process very efficient. However, with both technologies not being tested individually at commercial scale it is very unlikely to secure finance for such a hybrid concept and it is therefore not considered.

Further bankable concepts discussed include the use of CSP for air and feedwater heating as well as the generation of identical steam parameters as the host plant. However, none of the mature concepts considers CSP steam >430 °C which limits the conversion efficiency of the biomass feedstock.

3. Methods

The assessment aims to identify the best CSP–biomass hybrid plant configuration by investigating the technical, economic and environmental performance of 17 different scenarios. A case study approach is chosen to compare the scenario differences but the assessment is transferable to other locations when adapting site and cost conditions.

3.1. Modeling approach

All scenarios were thermodynamically and economically modeled with Thermoflex version 23.0. The software is well established for Rankine cycle systems and is widely used in academia and industry for actual CSP and conventional power plant modeling. All efficiency information is peak net cycle efficiencies based on $\eta = \text{MWe}/(\text{MW}_{\text{th}}\ \text{biomass} + \text{MW}_{\text{th}}\ \text{CSP})$.

Despite higher investment and lower cycle efficiency all 17 scenarios are modeled with air rather than water-cooling as water is typically a scarce commodity in high DNI areas with competing uses from agriculture and horticulture.

Both the biomass and CSP steam generators are supplied with the same feedwater source and generate identical steam flows/parameters, see Fig. 2. This allows the independent operation of both components and ensures acceptable part-load efficiency at night when only the biomass boiler is providing steam to the turbine. Thermal storage (TS) is not considered for all scenarios as in 2011 TS costs were still high, AU$ 90 kW h_{th} (Hinkley et al., 2011), and without additional incentives, such as a financial reward for capacity value, the biomass plant can provide electricity at lower cost when solar irradiance conditions prevent CSP operation. In case the 2020 TS cost predictions, AU$ 22/kW h_{th} (Hinkley et al., 2011), are met the technology would complement CSP–biomass hybrid plants well and the assessment therefore includes, technical, economic and environmental information on 1–7 h molten salt TS configurations. To maximize CSP generation without thermal storage all scenarios are designed with a solar multiple of 1.4.

Investment data derived from the Thermoflex database, which is considered quite accurate as modeling a 50 MWe Andasol type parabolic trough plant with 7.5 h of thermal storage in Spain resulted in the published € 300 m investment (Solar Millennium AG, 2006). Australian conditions such as higher labor and equipment prices are considered in all scenarios. With an assumed plant commissioning in 2016 the Thermoflex solar field investment is lowered by 10% to reflect 2015 pricing based on a reasonable learning curve (IRENA, 2012). Biomass boilers are not a standard Thermoflex component and its database is therefore less reliable. To maximize cost accuracy industry prices were obtained for this equipment (ERK Eckrohrkessel GmbH, 2013). Different to the Termosolar Borges plant this assessment considers only one and not two biomass boilers. Single biomass boilers are available to run >10 MWe steam turbines, achieve low part-load operation and reduce investment.

The economic assumptions are a plant lifetime of 30 years, 91.3% capacity factor for the biomass component, varying capacity factors for the CSP components (trough 18.3%, Fresnel 15.5% and tower 19.2%), commissioning in 2016, 65% debt finance, 8% debt interest rate, 7% discount rate, and biomass price of AU$ 50 t for forestry residues. A power purchase agreement (PPA) of AU$ 145 MW h is used, which is significantly lower than the AU$ 225 MWh a 64 MWe standalone CSP plant would need at Mildura (IT Power, 2012). The modeling includes capital and operational costs as well as annual escalation rates for inflation (3%), fuel (2%), electricity (3%) and water prices (4%). All investments shown are the owners total project cost consisting of the engineering, procurement and construction (EPC) price and 9% owner's soft cost covering permits, project management, legal and finance aspects of a power plant project. Payback periods, net present values and internal rates of return on investment (IRR) derive from the total project cost.

3.2. Technology selection

The aim of this assessment is to evaluate CSP–biomass hybrid concepts that can be financed immediately and therefore includes only CSP and biomass technologies that have >5 MWe reference plants. For CSP this includes parabolic trough with thermal oil (Solar Millennium AG, 2006), DSG (Krüger et al., 2012) and molten salt (Falchetta et al., 2009), solar towers with DSG (Abengoa Solar, 2011) and molten salts (García and Calvo, 2012), and Fresnel with DSG. These technologies are already assessed and found suitable for hybridisation with biomass (Peterseim et al., 2013). Fresnel using molten salts is promising and could reach working fluid temperatures of 550 °C (Smith and Cohn, 2012) but the technology is currently at proto-

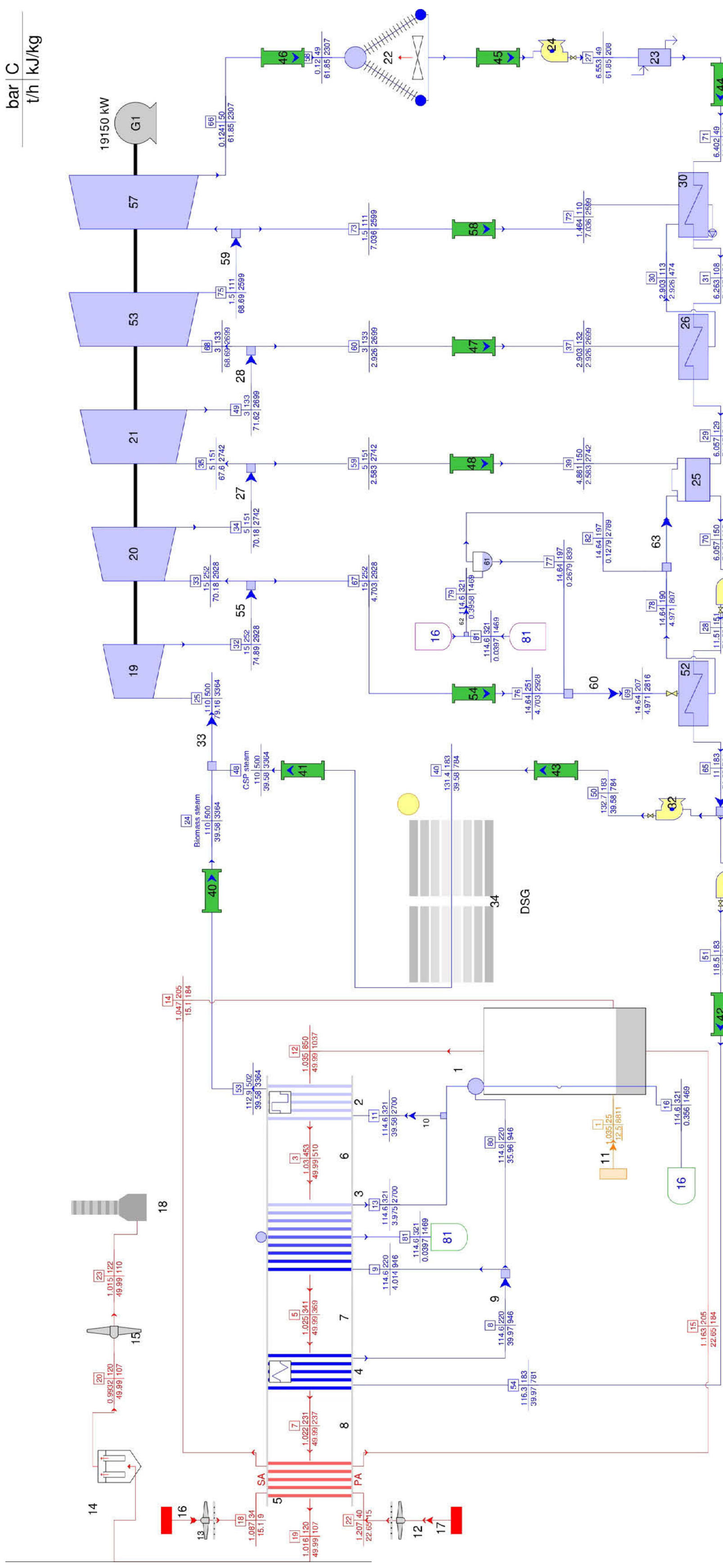

Fig. 2. Process diagram of a CSP–biomass hybrid plant using Fresnel and a fluidised bed with steam parameters of 500 °C at 110 bar (scenario 9); main components shown include biomass boiler (1–8) with fuel supply (11), baghouse filter (14), stack (18), solar field (34), steam turbine (19, 20, 21, 53, and 57), generator (G1), air-cooled condenser (22), feedwater heaters (26, 30, and 52), deaerator (25), pumps (24, 29, 32, and 56), fans (12, 13, and 15), and piping (40–48, 54, and 58).

Fig. 3. 5 MWe plants using parabolic trough with molten salt (left) (Falchetta et al., 2009) and DSG (middle) (Krüger et al., 2012) as well as 10 MWe biomass gasification plant with syngas combustion in a boiler (right) (Photograph courtesy ERK Eckrohrkessel GmbH, Berlin, Germany).

type scale and therefore not considered. Similarly volumetric air solar towers are being investigated with biomass (Coelho et al., 2012) but reference plants do not yet exist. Some data are provided to compare these concepts with selected CSP technologies.

Biomass conversion technologies include grate and fluidised bed systems (Spliethoff, 2010) as well as gasification units burning the producer gas in a boiler (ERK Eckrohrkessel GmbH, 2013). Grate systems have most references while fluidised bed systems are also mature for woody biomass (Spliethoff, 2010). Gasification references do exist for up to 20 MWe standalone biomass plants (Eckrohrkessel GmbH, 2012) and even larger retrofits to existing boilers (Metso Corporation, 2011). Therefore gasification with syngas firing in a boiler is considered mature for the plant capacity considered in this study.

Gasification systems producing a syngas for open or combined cycle engine/gas turbine operation are excluded as this technology is not considered mature yet for plant capacities >5 MWe. Fig. 3 presents references for the less mature but considered molten salt and DSG parabolic trough systems as well as biomass gasification.

3.3. Case study site selection and biomass fuel

The site selected for this analysis is near Mildura, Australia. The area has a DNI of 2198 kW h/m^2/year (Bureau of Meteorology, 2012), which is better than the 1800 kW h/m^2/year of the Termosolar Borges plant in Spain (Morell, 2012), and is home to one of Australia's prime horticulture and agriculture regions. In general the Mildura region is quite similar to the area where the Termosolar Borges plant is operating. Biomass feedstocks from horticulture, forest and urban residue streams as well as straw from agriculture are available and could provide the required energy equivalent of 100,000 t/a wood feedstock at 8.8 MJ/kg (forestry residues with 40% moisture content) for each scenario. Agroforestry could be another option for future fuel supply. The different nature and composition of biomass affects the power station's annual biomass demand and Table 1 provides information on other relevant feedstocks in the Mildura region. Several power plants using multiple biomass feedstocks, such as straw and wood chips, exist and the technology can be considered mature, for example 30 MWe Holstebro plant in Denmark (Andersen et al., 1992) and 25 MWe Sangüesa plant in Spain (Acciona Energía, 2002).

Table 1
Biomass quantities required to substitute 100,000 t/a of forestry residues.

Biomass material	Annual demand (t)	Calorific value (MJ/kg)	Moisture content (%)
Straw	66,200	13.3	13
Construction timber	57,100	15.4	9
Wood pellets	52,700	16.7	8.7

The maximum mean ambient temperature for Mildura is 23.8 °C (of Meteorology, 2013) and the plant's air cooling system is optimized for this temperature. Despite lower efficiencies air-cooling is considered as water is a precious commodity in the region and a power station would compete for it with other users, e.g. agriculture.

Mildura is in the state of Victoria which has one of the highest retail electricity prices in Australian Energy Market Commission (2011). This maximizes plant revenue and was another criterion for selecting this site. The electricity could be consumed locally but also exported into the national electricity market via existing transmission infrastructure.

4. Water–steam cycle analysis

Several options exist to increase the efficiency of a Rankine cycle systems, such as optimized feedwater heating, blowdown heat recovery and flue gas condensation. This section briefly outlines the effects of these options on the net cycle efficiency and provides the base case scenario (scenario 1) for the following CSP–biomass hybrid assessment.

4.1. Feedwater preheating

Three models are considered using single, double and triple feedwater heating. The comparison is based on a CSP–biomass hybrid plant with steam flow of 83 t/h at 80 bar and 380 °C generating 16.9 MWe, see Table 2. Rais-

Table 2
Feedwater heating effects on net plant efficiency.

Number of feedwater heaters	Feedwater temperature (°C)	Plant net capacity (MWe)	Net plant efficiency (%)
1	143	16.9	28.5
2	162	17.1	28.9
3	183	17.3	29.3

ing the high pressure feedwater temperature by 20 °C with bleed steam from the turbine increases the net cycle efficiency by 0.4% generating an additional 200 kW. Further increasing feedwater temperature to 180 °C increases the cycle efficiency by another 0.4%.

While utility scale power plants have at least 5 feedwater heater stages this is not practical for smaller plants but technically possible. The cost and additional complexity are the main barriers.

4.2. Blowdown heat recovery

Every boiler has a blowdown system and depending on the water quality and the operation philosophy blowdown quantities in industrial boilers range from 1% to 6%. Utility boiler blowdown rates are significantly lower, e.g. 0.1% reducing the effect of blowdown heat recovery.

With blowdown temperatures' being close to the saturation steam temperature it offers good potential for additional feedwater heating. The following data are based on 1% boiler blowdown as well as the aforementioned 3 stage feedwater concept and steam parameters. Recovering the boiler blowdown at 85 bar and using it in the high-pressure feedwater heater and deaerator reduces the steam turbine bleed slightly, therewith increasing net power generation by 26 kW.

The potential for blowdown heat recovery is not particularly high and therefore the concept is rarely implemented. However, a few installations exist, such as the Augusta pulp and paper plant in the US. This plant increased the boiler feedwater temperature by 10 °C and achieved a simple payback of only 6 months (US Department of Energy 2002).

4.3. Flue gas condensation

Generally, flue gas temperatures should be kept above the dew point to avoid acid corrosion on the boiler's low temperature heating surfaces. However, due to rising fuel costs and higher efficiency expectations some power stations installed flue gas condensers, such as the energy from waste plant in Malmö, Sweden (Friotherm AG, 2008) and the coal fired power station Schwarze Pumpe in Germany (Borsig Steinmüller GmbH, 2007). The concept can increase the cycle efficiency by up to 1% but depends on the power plant configuration and use of the low temperature heat, e.g. feedwater/air preheating or district heating/cooling. One reason for the limited implementation of flue gas condensers is the comparatively high investment as the small temperature differences between water and flue gas lead to larger heating surfaces which also have to be acid resistant.

Reducing the flue gas exit temperature from 120 °C to 70 °C, Malmö stack temperature (Friotherm AG, 2008), and using this heat to replace bleed steam from the low-pressure turbine generates 204 kW additional power (compared to blowdown scenario) taking the net plant capacity to 17.5 MWe. This equals a plant net efficiency of 29.6%.

Despite its promising potential this assessment does not consider fuel gas condensation as the comparatively high

Table 3
Technical comparison of hybrid options.

Scenario	CSP technology	Primary CSP working fluid	Biomass technology	Live steam temperature (°C)	Live steam pressure (bar)	Plant net capacity (kWe)	Peak net efficiency (%)
1 – PT + TO	Parabolic trough	Thermal oil	Grate	380	80	17,330	29.3
2 – PT + TO	Parabolic trough	Thermal oil	Fluidised bed	380	80	17,430	29.5
3 – PT + DSG	Parabolic trough	DSG	Fluidised bed	400	90	17,890	30.3
4 – F + DSG	Fresnel	DSG	Fluidised bed	400	90	17,910	30.4
5 – PT + DSG	Parabolic trough	DSG	Fluidised bed	450	100	18,530	31.5
6 – F + DSG	Fresnel	DSG	Fluidised bed	450	100	18,540	31.5
7 – ST + DSG	Solar tower	DSG	Fluidised bed	450	100	18,600	31.5
8 – PT + MS	Parabolic trough	Molten salt	Fluidised bed	500	110	19,060	32.2
9 – F + DSG	Fresnel	DSG	Fluidised bed	500	110	19,150	32.5
10 – ST + DSG	Solar tower	DSG	Fluidised bed	500	110	19,170	32.5
11 – ST + MS	Solar tower	Molten salt	Fluidised bed	500	110	19,080	32.3
12 – PT + MS	Parabolic trough	Molten salt	Fluidised bed	525	120	19,340	32.7
13 – ST + DSG	Solar tower	DSG	Fluidised bed	525	120	19,430	33.0
14 – ST + MS	Solar tower	Molten salt	Fluidised bed	525	120	19,370	32.8
15 – PT + MS	Parabolic trough	Molten salt	Gasification	540	130	19,400	32.8
16 – ST + DSG	Solar tower	DSG	Gasification	540	130	19,540	33.2
17 – ST + MS	Solar tower	Molten salt	Gasification	540	130	19,410	32.9

Table 4
Economic comparison of CSP–biomass hybrid scenarios.

Scenario	Total plant investment (mAU$)	Specific plant investment (AU$/MW)	Specific cost reduction (%)	Years payback	Net Present Value (AU$m)	Internal rate of return on investment (%)
1 – PT + TO	115	6.7		15.8	26.0	8.2
2 – PT + TO	115	6.6	0	15.7	26.9	8.3
3 – PT + DSG	115	6.4	2	15.3	31.1	8.5
4 – F + DSG	85	4.8	27	9.7	50.4	10.8
5 – PT + DSG	115	6.2	5	14.6	36.6	8.9
6 – F + DSG	86	4.6	29	9.1	55.4	11.2
7 – ST + DSG	97	5.2	20	10.5	51.7	10.4
8 – PT + MS	118	6.2	5	14.6	38.0	8.9
9 – F + DSG	86	4.5	31	8.6	59.8	11.5
10 – ST + DSG	97	5.1	22	9.9	56.3	10.7
11 – ST + MS	99	5.2	21	10.4	53.8	10.4
12 – PT + MS	120	6.2	5	14.4	39.3	9.0
13 – ST + DSG	98	5.0	23	9.7	57.9	10.8
14 – ST + MS	100	5.2	21	10.2	55.5	10.5
15 – PT + MS	120	6.2	5	14.3	39.8	9.1
16 – ST + DSG	98	5.0	23	9.6	58.8	10.9
17 – ST + MS	101	5.2	21	10.2	55.6	10.5

Table 5
Renewable energy generation, CO_2 abatement potential.

Scenario	Annual generation potential (MWh)	CO_2 abatement potential for forestry residues wood (t/a)	CO_2 abatement potential for straw (t/a)
1 – PT + TO	83,220	47,800	50,700
2 – PT + TO	83,650	48,100	51,000
3 – PT + DSG	85,870	49,500	52,400
4 – F + DSG	83,760	48,200	51,100
5 – PT + DSG	88,940	51,500	54,400
6 – F + DSG	86,730	50,000	52,900
7 – ST + DSG	90,070	52,200	55,100
8 – PT + MS	91,510	53,100	56,000
9 – F + DSG	89,580	51,900	54,800
10 – ST + DSG	92,810	53,900	56,800
11 – ST + MS	92,380	53,700	56,600
12 – PT + MS	92,860	54,000	56,900
13 – ST + DSG	94,090	54,800	57,700
14 – ST + MS	93,790	54,600	57,500
15 – PT + MS	93,130	54,100	57,000
16 – ST + DSG	94,630	55,100	58,000
17 – ST + MS	94,010	54,700	57,600
17 – ST + MS + 1 h TS	99,570	58,300	61,200
17 – ST + MS + 3 h TS	104,520	61,400	64,300
17 – ST + MS + 5 h TS	107,820	63,500	66,400
17 – ST + MS + 7 h TS	110,490	65,200	68,100

investment would reduce the plant's economic viability in Australia's traditionally low cost electricity market. However, the additional capacity given can be added to the scenarios discussed later on.

5. Results

The technical, economic and environmental results shown for the 17 different scenarios are based on triple feedwater heating and blowdown heat recovery. Some information is provided on the impact of molten salt TS and less mature plant concepts.

To clearly identify the scenarios and its different results in Tables 3–5 an abbreviation code is used where for example 1−PT+TO stands for scenario 1 using the parabolic trough technology with thermal oil. Each CSP technology is paired with the biomass technology outlined in Table 3, either grate, fluidised bed or gasification.

5.1. Technical analysis

This assessment compares 17 different scenarios with steam parameters from 375 °C at 80 bar to 540 °C at 130 bar, see Table 3. The base case scenario 1 assumes the integration of biomass into a conventional parabolic trough plant with both the biomass and CSP steam generator generating identical steam parameters. The highest steam parameter scenarios compare solar towers (DSG and molten salt) and parabolic trough (molten salt) with biomass gasification and syngas firing in a boiler.

Scenario 16 using a solar tower with DSG reaches the highest net cycle efficiency, 33.2%, and plant capacity, 19,540 kW, compared to all other scenarios, see Table 3. Scenario 13 ranks second with scenario 17 being third. The efficiency increase from scenario 1 to 16 is 13%. The two other scenarios in this steam parameter category (15 and 17) have slightly lower efficiencies, −0.4% and −0.3%, as the primary molten salt and secondary water-steam cycle leads to slightly higher parasitic losses.

The results for the 525 °C and 500 °C categories have the DSG scenarios 13, 10 and 9, as the best concepts for CSP biomass hybrids. When comparing the annual generation scenarios 13 and 10 perform best in these groups as solar towers have higher capacity factors than Fresnel, see Table 5. It is interesting to notice that the change from parabolic trough with thermal oil (scenario 2) to DSG (scenario 3) with only slightly higher steam parameters increases cycle efficiency by almost 1%. As seen in Table 3 cycle efficiency increases stronger from 375 to 500 °C scenarios, +3.2%, than in the 500–540 °C scenarios, +0.7%, which is in line with expectations as the efficiency curve flattens with higher steam parameters.

The differences between the combustion systems is only marginal (scenarios 1–2 and 14–15) with fluidised bed and gasification systems having lower unburned carbon contents in the ash than grates, <1% compared to <3%, and lower excess air requirements, 20% compared to 25%. The main benefit of the gasification system with syngas firing in a boiler is the high ash retention in the gasifiers and subsequently lower high-temperature corrosion problems on the boiler's superheater banks.

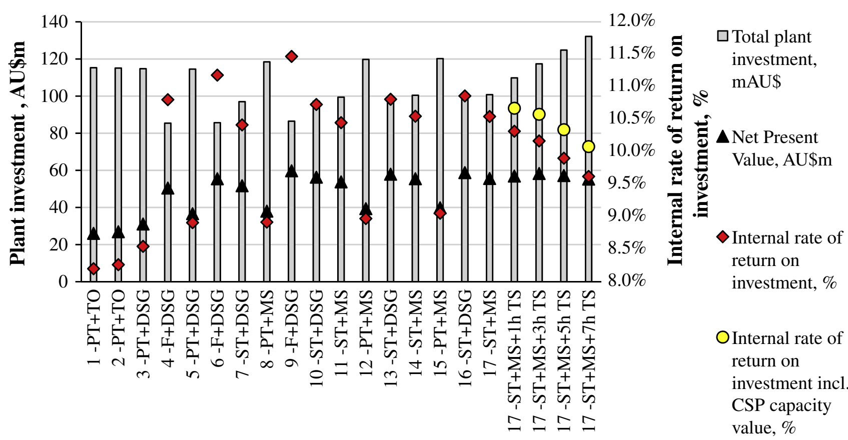

Fig. 4. CSP–biomass hybrid plant investment, NPV and IRR.

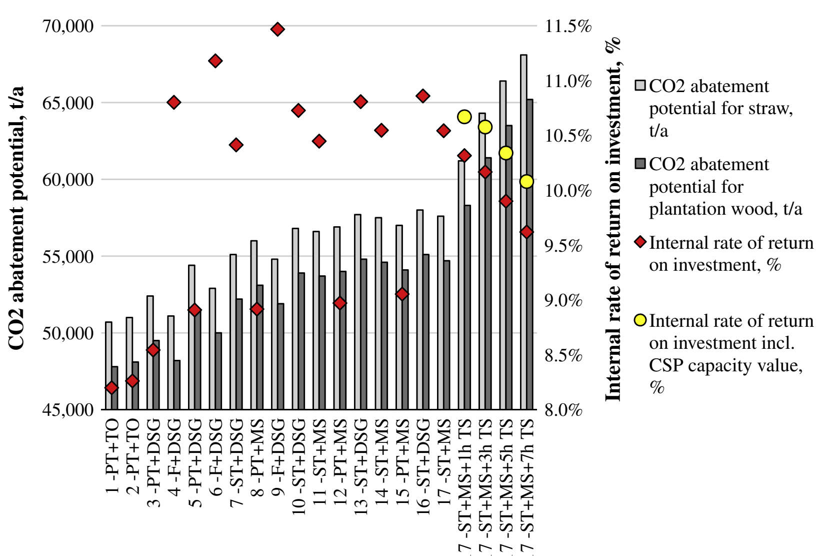

Fig. 5. CO_2 abatement potential vs. IRR with and without CSP capacity value.

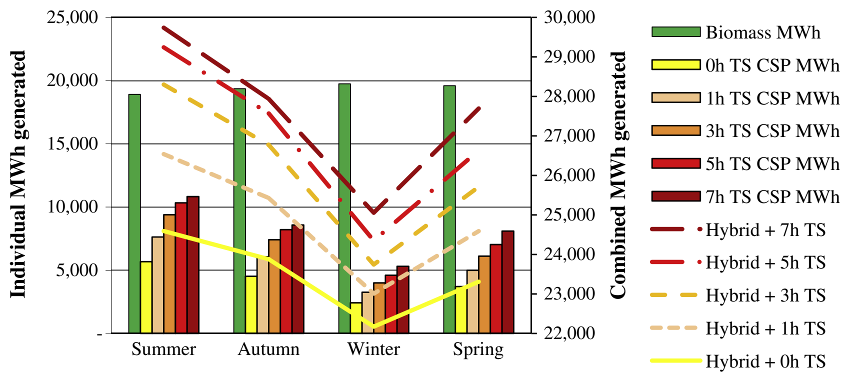

Fig. 6. Seasonal net electricity generation for a scenario 17 CSP–biomass hybrid plants with different hours of thermal storage.

5.2. Economic analysis

Different to the best technical scenario (16) the commercially most attractive one at this point in time is scenario 9, which uses Fresnel, with an IRR of 11.5% (scenario 16 ranks third with 10.9% IRR), see Table 4. Compared to the base case scenario 1 the IRR increases from 8.2% to 11.5%, a 40% increase. Despite a lower capacity factor and the scenario only ranking 8th in the cycle efficiency criterion the significantly lower specific investment, AU$ 4.5 m/MWe compared to AU$ 5 m/MWe for scenario 16, leads to the highest IRR and NPV. The lower Fresnel capacity factor and investments identified are in line with other studies (Morin et al., 2012; Narula and Gleckman, 2012). Only scenario 9 meets the 11.5% IRR criterion typically required by utilities (Sargent & Lundy LLC Consulting Group, 2003). The even lower cycle efficiency scenario 6, also Fresnel, ranks second despite its annual generation being 7900 MWh lower than scenario 16. The low Fresnel investment is a strong incentive for the technology.

The scenarios with the highest annual generation (16, 13 and 17) have, due to the higher investments, slightly lower IRR's (10.9%, 10.8% and 10.5%) which might still be of interest to conservative investors. The mature parabolic troughs with thermal oil (scenarios 1–2) have the lowest IRR (8.2% and 8.3%) and NPV (AU$26 m and AU$26.9 m) due to the higher specific investment and lower cycle efficiencies. Therefore reducing the efficiency of the biomass component to match the CSP steam parameters is not recommended, particularly when considering that the biomass generates the majority of annual output, see Fig. 6.

With changing CSP technologies the specific hybrid plant investment decreases by 31% from scenario 1 to 9, which is substantial reduction without encountering higher technology risk as all technologies are demonstrated and supplied by well established companies which provide performance guarantees. Scenarios 6 and 4, also Fresnel, have the second and third lowest specific investment. The realization of a scenario 9 plant would not only directly stimulate the local economy but also indirectly therewith increasing the overall project stimulus to AU$ 114 m, when assuming 29% international procurement (Caldés et al., 2009) and a value multiplier of 1.86, combined from 1.42 multiplier for biomass plant including fuel procurement (Gan and Smith, 2007) and a 2.3 CSP multiplier (Caldés et al., 2009). That is a significant investment for a rural region such as Mildura.

Adding any 1–7 h molten salt TS configuration to scenario 17, technology with highest IRR and commercially proven TS, reduces IRR and NPV but increases annual electricity generation and CO_2 abatement potential significantly, see Figs. 4 and 5. However, when including an additional value of AU$ 21 MWh for CSP electricity dispatchability, which has been discussed in the Australian context recently and consists of AU$ 20 MWh capacity value and AU$ 1 MWh ancillary services (IT Power, 2012), the IRR increases for 1 h TS to 10.7%, for 3 h TS to 10.6%, for 5 h to 10.3% and for 7 h TS to 10.1%, see Fig. 4. This means that up to 3 h TS the IRR is higher than the 10.5% for scenario 17 without TS but larger TS reduces the IRR due to higher cost and a slowing capacity factor increase, see Fig. 6. If Fresnel references with molten salt and TS would exist, currently being investigated with molten salt temperatures up to 550 °C and 16 h TS (Smith and Cohn, 2012), it would be the least cost TS scenario.

With the biomass providing the majority of the annual electricity its capacity factor should be kept a high as possible and actual plants do reach 91.3% (8000 h/a), e.g. 25 MWe Sangüesa in Spain (Acciona Energía, 2002). However, such high capacity factors require good plant maintenance and fuel logistics which might not be available everywhere and at all times. A lower biomass component capacity factor of 88% would reduce the scenario 9 IRR to 11.1% and to 10.8% when assuming 85%.

This assessment is based on equal finance for all technologies considered. However, the economic results strongly depend on the financiers perceived technology risk. Finance institutions familiar with a particular CSP technology would be able to provide lower cost finance for this technology compared to others therewith altering the investment and IRR results provided in Table 4. These risk factors can vary significantly between financiers and have to be investigated on a project by project basis.

5.3. Environmental analysis

Due to the higher cycle efficiency and best capacity factor the solar tower scenarios 16, 13 and 17 achieve the highest annual renewable electricity generation with up to 94,630 MWh, see Table 5. The annual output of the least performing scenario (1) is almost 14% lower.

The 2010 CO_2 intensity of electricity generation in Australia was 841 kg CO_2/MW h (IEA, 2012) and 2050 modeling for the Australian Government Treasury projects that the national annual electricity demand increases to 400 TWh while CO_2 emission from electricity generation fall to around 68 Mt (ROAM Consulting Pty Ltd, 2011), which equals a CO_2 intensity of 162 kg/MWh. This is not going to be a linear decline (~740 kg CO_2/MWh in 2020, ~720 kg CO_2/MWh in 2030 and ~500 kg CO_2/MWh in 2040) with the strongest CO_2 reductions from 2040-50. For the 2016-45 plant lifetime considered this leads to an average CO_2 intensity of Australia's electricity sector of ~640 kg/MWh. However, it needs to be highlighted that uncertainties around the actual CO_2 intensity development exist with electricity demand currently falling rather than increasing and the share of coal fired generation decreasing faster than expected (pitt&sherry, 2012). Biomass production and transport emissions have to be deducted from the CO_2 abatement potential and this assessment considers 54 kg CO_2/t for plantation softwood residues and 25 kg CO_2/t for straw based on a 50 km transport distance (Farine et al., 2011). The forestry residues scenario 16 has the highest annual CO_2 abatement potential, up to 55,100 t, closely followed by scenarios 13 and 17, see Table 5. Scenario 1 has with up to 47,800 t the lowest annual CO_2 abatement potential. Adding TS would significantly increase the CO_2 abatement potential to 65,200 t/a (scenario 17 with 7 h TS) but reduce IRR to 9.6% unless energy dispatchability is valued or TS costs decrease significantly, see Fig. 5. In addition to a higher CO_2 abatement TS would increase the annual biomass conversion efficiency by reducing steam turbine part-load operation. The CO_2 abatement potential for a straw fired CSP–biomass hybrid is slightly higher due to its lower production and transport emissions.

With the CSP and biomass components sharing a joint steam turbine the turbine operates at part-load when CSP is not delivering its design capacity, therewith reducing cycle efficiency. The part-load steam turbine operation at night and during extended cloud coverage reduces the biomass capacity in scenario 17 from 9.7 MWe with CSP to 9 MWe without CSP contribution, which equals a lost annual biomass output of 2580 MWh (−3.3%) when comparing it to a 19.4 MWe standalone biomass plant. However, the loss through part-load operation has to be compared to the annual use of 100,000 t forestry residues in a standalone biomass plant which has an inherently lower efficiency, 28.6% compared to 32.9% in scenario 16, and there with a lower net plant capacity of 8.8 MWe. Considering this the CSP–biomass hybrid generates and additional 4890 MWh/year. This benefit increases with 1 h TS to 5660 MWh, with 3 h TS to 5720 MWh, with 5 h TS to 5770 MWh and with 7 h TS to 5820 MWh as the steam turbine operates more hours at its design point.

Even when considering TS the majority of the electricity is generated through the biomass component as its capacity factor is significantly higher, see Fig. 6. The plant generation over the year is not constant decreasing up to 16% in winter compared to summer. The CSP summer-winter generation difference is with 57% significantly larger and the 4.4% higher biomass plant output in winter compared to summer, caused by lower ambient temperatures, can only partly offset this. The lower seasonal generation variation of a hybrid plant is beneficial for grid operators and could be further decreased by adding larger TS or extra capacity natural gas burners to the biomass boiler.

From a specific land use land use perspective the Fresnel-biomass scenarios perform best with ~1.1 ha/MWe followed by parabolic troughs with ~1.3 ha/MWe and solar towers with ~2 ha/MWe. The biomass plant requires 2 ha in all scenarios. Adding TS would increase land use up to 3.4 ha/MWe (scenario 17 with 7 h TS). The plant footprint is not a main criterion for utility scale CSP as such plants are usually remote, but it is relevant for distrib-

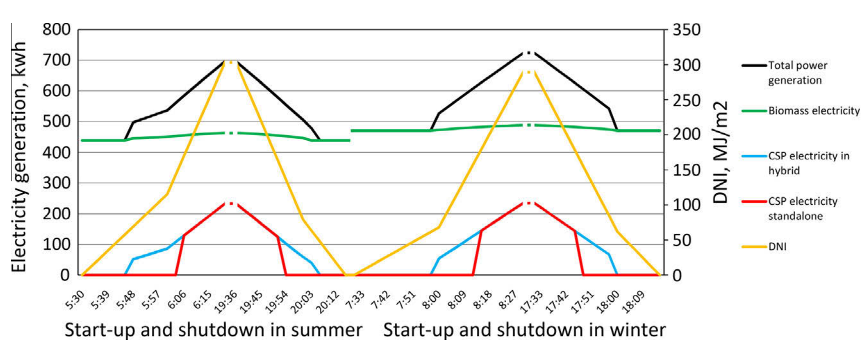

Fig. 7. Summer (left) and winter (right) electricity generation in the morning and evening hours for a CSP only and hybrid plant.

uted CSP systems as these are typically closer to urbanizations therewith facing higher land prices.

With all plant configurations designed with air-cooling water consumption is already minimized with only mirror cleaning and boiler blowdown being relevant water consumers. While the boiler blowdown depends on the water quality, and is the same percentage for all scenarios (1%), water consumption for mirror cleaning varies with the CSP technology. Cleaning robots are developed to minimize water consumption and it seems likely that Fresnel systems require least cleaning water followed by troughs and tower systems.

5.4. Hybrid vs. stand-alone cost comparison

The hybridization of CSP with biomass, or other energy sources, can reduce the CSP investment of the assessed scenarios by 12% compared to a standalone CSP plant. The specific 2015 investment for the 9.6 MWe CSP share of scenario 9, Fresnel technology, is AU$ 5.7 MWe while a 9.6 MWe standalone CSP without TS would require a specific investment of AU$ 6.4 MWe. The lower investment results from sharing plant equipment, such as steam turbine, condenser and auxiliary equipment. Solar tower hybrids could also share plant infrastructure by using the biomass plant's stack to support the receiver. In this model the solar tower height is 60 m which is twice the height required for the stack of the biomass plant. Adapting the stack to support receiver equipment is possible and has been discussed for integrated solar combined cycle (Peterseim et al., 2012) and CSP–biomass hybrid plants (Peterseim et al., 2013). Tower construction is 5% of a solar tower project investment (Hinkley et al., 2011) and not all of that could be saved but 3% are realistic at this plant scale.

Different to comparing the specific investment a comparison of plants with identical annual outputs shows the CSP hybrid benefits more clearly. To meet the annual output a of a scenario 9 CSP–biomass hybrid (AU$ 86 m) a 66 MWe standalone Fresnel plant would be required with a 2015 investment of AU$ 280 m. To meet the demand of scenario 16 (AU$ 98 m) a 56 MWe standalone solar tower costing AU$ 295 m would be required. TS can reduce the plant capacity and a 3 h TS molten salt solar tower plant would require a capacity of 34 MWe with an associated investment of AU$ 255 m. While the specific investment reduction of CSP–biomass hybrids is only 12% the investment reduction to generate the same annual electricity output is up to 69%. All three standalone CSP options mentioned would require a PPA in excess of AU$ 200 MWh to be commercially viable in Australia.

In addition to lower investment the annual electricity generation of a CSP–biomass hybrid plant is slightly higher, 0.4%, compared to a CSP standalone because the hybrid plant does not require the 25% minimum steam turbine load to commence/cease operation as the turbine is already/remains in operation with steam from the biomass boiler. Considering a minimum solar field steam output of 10% means that even small stream flows can be converted into electricity. Fig. 7 shows the electricity generation during the summer/winter morning and evening hours for a scenario 16 plant. It can be observed that the CSP steam in a hybrid plant is used circa 24 min longer in summer and winter than in the CSP only plant. Assuming no additional start-ups and shut-downs during the day this adds up to an additional annualized output of 279 MWh which equals additional revenue of AU$ 40,425. When considering one additional steam turbine start/stop every second day the additional annual output increases to 418 MWh and AU$ 60,640 additional revenue.

6. Conclusion

The assessment shows that at the moment the best technical and environmental CSP–biomass hybrid configuration, being solar tower and gasification, is not the best commercial choice, being Fresnel and fluidised bed. While the efficiency differences for the 17 scenarios reach 13% the investment variations are with 31% significantly larger. The results also show that, based on identical annual electricity generation, the CSP–biomass hybrid plant investment is up to 69% lower compared to a standalone CSP plant without thermal storage. This makes CSP–biomass hybrids commercially viable at a power purchase price of AU$ 145 MWh compared to >AU$ 200 MWh for standalone CSP systems in Australia while having a more stable annual generation curve.

The integration of thermal storage can increase the annual generation of CSP–biomass hybrid plants up to 17% (7 h TS) but currently requires a capacity value payment to be competitive with a no storage plant. With thermal storage cost expected to decrease significantly by 2020 future CSP–biomass plants are likely to have thermal storage. However, even with extensive thermal storage the majority of the electricity, 70%, still derives from the biomass resource. The first CSP–biomass hybrid in Spain using parabolic troughs will provide financiers and operators with more expertise about such concepts and therewith reduce risk and plant finance.

Despite the benefits CSP–biomass hybrid plants offer it has to be acknowledged that the sites for such plants are limited as only few locations have a sufficiently high DNI and biomass resource. It is therefore a niche solution worth exploring further as its lower cost can pave the way for CSP into traditionally low cost electricity markets, such as but not limited to Australia.

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4.4.2 External CSP steam superheating with biomass

The following publication investigates the use of various biomass and waste feedstocks to raise steam parameters in a conventional parabolic trough plant, through external steam superheating. The analysis considers the technical, economic and environmental impacts of the different scenarios.

In addition to the process diagram shown in Figure 2 in this paper, two additional process diagrams for other biomass and waste feedstocks, scenarios 1 air-cooled and 3 air-cooled, can be found in the appendix.

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Increasing the efficiency of parabolic trough plants using thermal oil through external superheating with biomass

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ABSTRACT

It is well understood that the cost of concentrating solar power (CSP) will need to decrease quickly to ensure competitiveness with photovoltaic (PV) systems and other forms of power generation. Research and development on CSP plant components is crucial in order to reduce costs but is typically time consuming. New CSP plant concepts combining proven technologies with CSP represent another option that can be implemented quickly.

This paper investigates the use of several biomass materials to externally superheat steam in conventional parabolic trough plants. Currently, parabolic trough plants are easiest to finance and external steam superheating can overcome the lower efficiencies compared to other CSP technologies. Seven scenarios, each air and water cooled, with steam parameters ranging from 380 °C at 100 bar to 540 °C at 130 bar have been modeled, and the results presented here are based on a 50 MWe plant with 7.5 h molten salt thermal storage.

Our results show that the peak solar to electricity net efficiency increases up to 10.5% while the specific investment can decrease immediately from AU$8.2m/MWe to AU$6.3m/MWe, a 23.5% reduction. That is significant considering the expected 17–40% CSP cost reduction targets by the end of this decade. The modeling shows that even major fuel and water price changes are significantly less relevant than small changes in the agreed electricity purchase price.

The technical, economic and environmental analysis reveals that external superheating with biomass can provide significant benefits, is able to use a variety of fuels and despite a limited global market, could immediately enable the implementation of several hundred MWe of CSP capacity at lower cost.

1. Introduction

Compared to the 98 GWe of worldwide installed photovoltaic (PV) capacity; concentrating solar power (CSP) is lagging behind with only 3 GWe installed capacity at the end of 2012 [1]. This significant difference is expected to remain with predictions of 308 GWe PV compared to 12 GWe CSP capacity by 2018 [1]. Therefore new technologies, innovative power plant concepts, and learning curve advancements are required to increase the CSP global market share and competitiveness against PV. The conversion of the first 500 MWe and potentially second 500 MWe phase of the 1000 MWe Blythe Solar Power Project, US, from parabolic trough to PV is the most outstanding example so far [2]. New technologies such as solar tower and Fresnel plants promise to increase efficiency and reduce cost of electricity but financing such plants is still more complicated than well-proven parabolic trough plants.

Because of its long track record parabolic trough plants had a 94% market share of all CSP technologies at the end of 2011 [3]. This technology is the most mature, has with the 280 MWe gross Solana project the largest CSP plant under construction [4], and is therefore easiest to develop and finance at this point in time. However, new tower and Fresnel plants coming online will alter the market share in their favor and therefore parabolic trough providers have to find ways to increase efficiency and decrease costs. Several options to do this exist including the use of new heat transfer fluids, such as advanced thermal oils, direct steam generation (DSG) or molten salts, as well as enhanced collectors/receiver

Abbreviations: CSP, concentrating solar power; PV, photovoltaic; AU$, Australian Dollar (AU$/US$ = 0.96); CapEx, capital expenditure; IRR, internal rate of return on investment; DNI, direct normal irradiance; BFB, bubbling fluidised bed; AC, air-cooling; WC, water-cooling; NPV, water-cooling; StE efficiency, solar to electricity efficiency.

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tubes. However, these developments take time, and therefore this paper focuses on external steam superheating, as this concept can immediately increase plant efficiency, thereby reducing the size of the solar field, and subsequently reducing plant investment by up to 23.5%. This is already within the 2020 cost reduction targets of 17–40% [3,5,6].

It is well accepted that CSP hybrids can reduce capital expenditure (CapEx) significantly and several plants in operation worldwide verify its benefits, e.g., Liddell in Australia [7], Next Generation in the USA [8], Kuraymat in Egypt [9] and Termosolar Borges in Spain [10]. Furthermore, several studies investigate the hybridisation of CSP with coal [11,12], gas [13,14] and geothermal [15,16] energy sources. This paper investigates the novel concept of using biomass to externally superheat the steam of a conventional 50 MWe parabolic trough plant with 7.5 h thermal storage from 380 °C up to 540 °C. In principle, external superheaters using natural gas could even generate supercritical steam parameters, but this is not possible with biomass in practice due to the problem of high-temperature corrosion on the superheater tube banks. Different fuels and corresponding maximum steam parameters are compared in terms of plant performance and cost as well as environmental impact. The use of biomass for external superheating makes excellent use of small biomass resources, such as those under 50,000 t/year, which would otherwise be used in small-scale biomass plants with inherently low efficiencies or not be used at all.

CSP-biomass hybrid plants are likely to be a niche market with only limited locations worldwide where both resources are sufficiently abundant. However, several countries meet this condition, including but not limited to, Australia, Greece, Spain, Turkey, India, China and Brazil, which offers the potential to implement CSP in these markets at lower cost and advance the industry along the technology learning curve. Also other fuels can be used for external superheating including biogas and natural gas.

2. Hybrid concepts for CSP and biomass

Hybrid plants not only reduce the cost of CSP but also have the potential to move CSP out of remote/arid into regional/semi-arid/agricultural regions where biomass and other waste materials are available. Typically, a CSP standalone plant requires a direct normal irradiance (DNI) of >2000 kWh/m^2/year but the specific CapEx reduction of CSP-biomass hybrid plants enables locations with DNI levels of only >1700 kWh/m^2/year [17]. Locations with low/negative cost solid fuels, such as waste materials, are preferable to maximise financial viability.

2.1. Current concepts

Some proposals to combine CSP with biomass or waste materials using dish systems were discussed briefly in the 1980s [18]. However, due to technical and financial issues no plants were built. It took another 25 years before construction of the first commercial CSP-biomass hybrid plant commenced near Lleida, ca. 150 km west of Barcelona, Spain [19], see Fig. 1. The 22.5 MWe Termosolar Borges plant came on-line in late 2012 [10], is located further north than any other CSP project in Spain and uses the mature parabolic trough technology with thermal oil [20]. Several other studies investigated the hybridisation of parabolic trough plants with biomass for high temperature/pressure turbine steam and feedwater heating [17,21–23] but no other project has yet commenced construction.

Alternatively, several Fresnel hybridisation options with biomass and waste materials have been investigated, such as high temperature/pressure turbine steam, combustion air and feedwater heating [24–27]. The benefit of using Fresnel would be steam temperatures of up to 500 °C [28], lower CapEx expectations and subsequently improved cycle efficiencies and economic viability. However, no reference plants yet exist for this CSP configuration.

Similarly, solar towers with molten salts and DSG are being investigated in combination with biomass [29] as are solar towers using a volumetric air receiver [30]. Due to the poor reference situation of volumetric air receiver tower systems and the higher complexity of such a system it is expected that solar towers with DSG or molten salts are easier to finance. Tower hybrids are promising due to high cycle efficiencies and lower cost energy storage.

2.2. Biomass fired external superheater

The purpose of an external superheater is to increase the cycle efficiency of power plants with inherently low efficiencies. Several factors can limit cycle efficiency including high temperature corrosion issues inside the boiler, as in energy from waste plants, or temperature limitations of the working fluid, as in parabolic trough plants using thermal oil.

The concept is based on forwarding "low" temperature steam from a boiler/heat exchanger to a separately fired heater, the external superheater, which uses a designated fuel to raise the steam temperature to the desired level, e.g., from 380 °C to 540 °C, see Fig. 2. The flue gas exit temperature leaving the superheater section is above the steam inlet temperature and the flue gas therefore still contains a significant amount of energy suitable for preheating boiler feedwater and combustion air.

The Holstebro, Denmark energy from waste/biomass plant, started implementing natural gas fired external superheaters in the 1990s to increase cycle efficiency by further superheating the 420 °C steam from the solid fuel fired boilers to >540 °C [31]. Similarly, some energy from waste plants adjacent to combined cycle gas turbine power stations provide steam at around 400 °C to the heat recovery steam generator for further superheating to >530 °C, e.g., Moerdijk in the Netherlands [32], Mainz in Germany [33] and Bilbao in Spain [34].

Fig. 1. First CSP-biomass plant under construction near Lleida, Spain (left) and its biomass fuel (right).

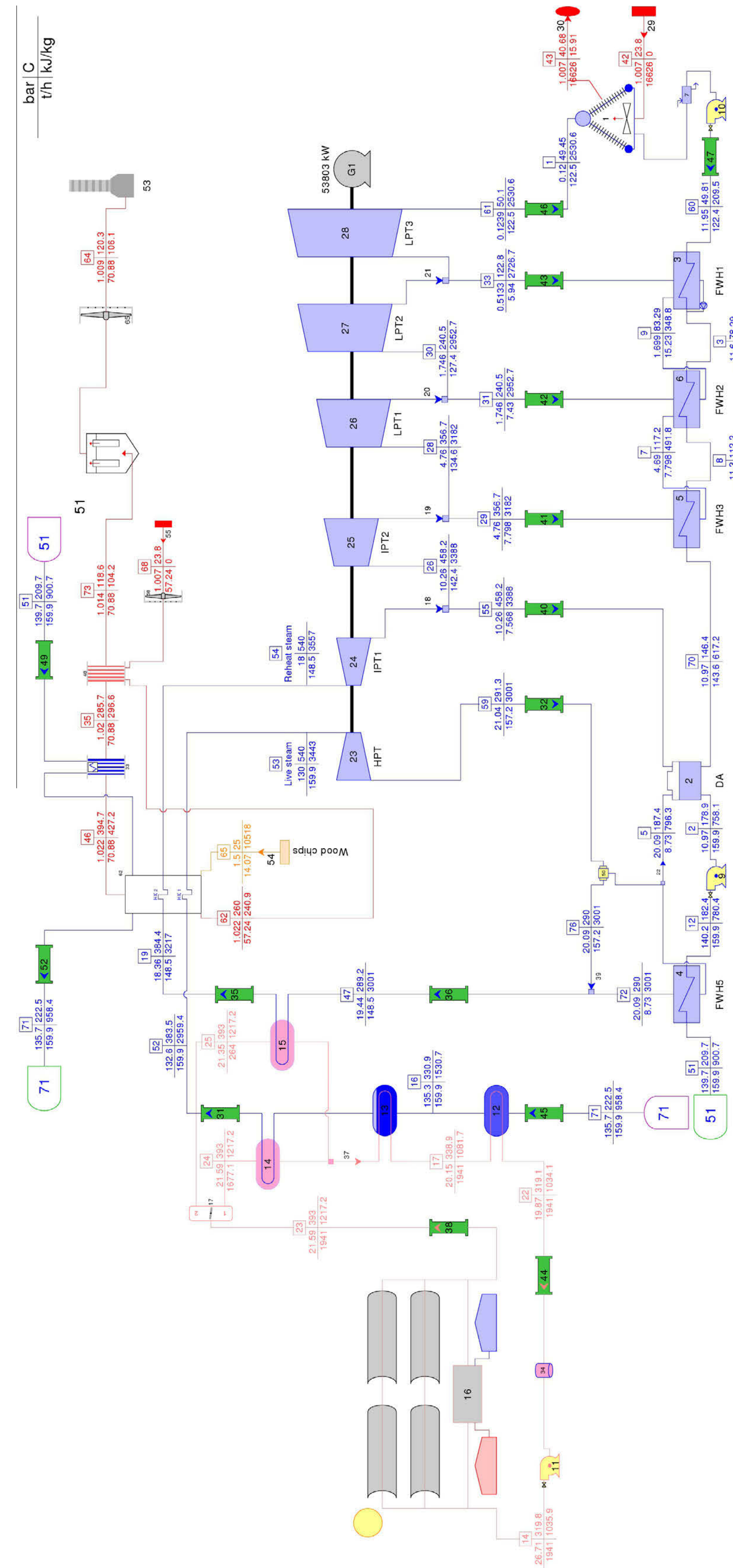

Fig. 2. External superheater concept using wood chips (scenario 6).

Table 1
Technical and economic inputs into scenario modeling.

Plant commissioning	2016	Power purchase agreement	AU$200/MWe
Full load hours per year	3500 [39]	Debt finance	65%
Plant lifetime	40 Years [39]	Debt interest rate	8%
AC condenser back pressure	0.12 bar	Discount rate	7%
WC condenser back pressure	0.08 bar	Water price	AU$1.8/m^3 [42]

Table 2
External superheater fuel specifications.

Biomass fuel	Calorific value (MJ/kg)	Moisture content (%)	Fuel price (AU$/t)
RDF	14.0	22	0
Urban wood waste	15.7	10	20
Wood waste from forestry	10.5	40	50
Stubble	13.3	13	60

The first parabolic trough plant with an external superheater recently commenced operation near Abu Dhabi in the UAE, 100 MWe Shams One [35]. The natural gas fired external superheater increases the steam temperature from 380 °C to 540 °C and provides around 18% of the plant's total heat input [35].

The external superheater concept as described is well proven with natural gas, however the use of biomass is novel. This configuration has the potential of providing fully renewable energy with low technical risk due to the available experience and expertise with external superheaters and standalone biomass plants generating steam temperatures up to 540 °C.

Grate, fluidised bed combustion and some gasification systems are suitable for the solid fuels considered, as described in Table 2. Grate systems are the most mature [36] but fluidised bed systems are also very well proven at capacities <30 MWth. Several gasification systems burning producer gas in a designated combustion chamber operate successfully. These systems provide benefits in regards to higher dust retention in the gasifiers resulting in lower dust loads passing through the superheater banks [37]. Because of the high combustion efficiency, good reference situation and a variety of suppliers a bubbling fluidised bed (BFB) system has been chosen for the external superheater modeling in this paper. The cost difference between grate and BFB systems is minimal. Grates have a lower investment, but fluidised bed systems require less surplus air, therefore reducing the flue gas volume and consequently the component size downstream of the furnace. Gasification systems are similar in cost to grates while requiring less surplus air.

The main benefit of the proposed concept is the solar field size reduction, which is the most capital intensive individual component of a parabolic trough plant [3,38], without using fossil fuels. This factor, in combination with lower financing cost for a parabolic trough plant would lead to lower electricity generation costs.

3. Plant modeling

The plant modeling is based on the concept outlined in section 2.2 and considers different biomass feedstocks as well as different air and water cooling configurations.

3.1. Methodology and scenarios

The technical and economic modeling work was carried out with Thermoflex version 23.0, which is a well accepted and widely used software in academia and industry.

Parabolic trough plants, without external superheating, are well proven with >50 plants in operation worldwide. To minimise finance risk all scenarios in this assessment are based on a 50 MWe plant capacity with 7.5 h molten salt thermal storage system, such as Andasol I–III, as there is significant expertise with this plant configuration.

Initially, higher temperature storage at 540 °C downstream of the external superheater was considered but this would require more changes to the standard 50 MWe parabolic trough concept

Table 3
Technical concept comparison.

Scenario	Biomass fuel	Live steam temperature (°C)	Live steam pressure (bar)	Peak StE gross plant efficiency (%)	Peak StE net plant efficiency (%)	Annual biomass demand (t)
1 AC	No ext. SH	380	100	27.1	24.4	–
1 WC	No ext. SH	380	100	28.0	25.0	–
2 AC	RDF	430	105	28.0	25.2	14,270
2 WC	RDF	430	105	28.8	25.7	13,910
3 AC	Urban wood waste	450	110	28.5	25.6	16,890
3 WC	Urban wood waste	450	110	29.2	26.1	16,520
4 AC	Wood waste	480	110	28.8	26.0	33,980
4 WC	Wood waste	480	110	29.6	26.4	33,250
5 AC	Wood waste	510	120	29.4	26.5	42,040
5 WC	Wood waste	510	120	30.2	27.0	41,020
6 AC	Wood waste	540	130	30.0	27.0	49,250
6 WC	Wood waste	540	130	30.8	27.5	47,600
7 AC	Stubble	540	130	29.8	26.9	39,340
7 WC	Stubble	540	130	30.7	27.5	38,050

and this concept was abandoned to minimise technical/financial risk. However, higher temperature storage would reduce investment requirements and is therefore a subject for further study.

Seven scenarios, both air and water cooled with steam reheating are compared, with steam parameters ranging from 380 °C at 100 bar to 540 °C at 130 bar, as shown in Table 3. The base-case is a parabolic trough plant without external superheating. All other scenarios are based on different biomass feedstocks and consider that the nature and composition of the solid fuel determines the maximum steam parameters without encountering high-temperature corrosion and ash fusion problems on the superheater tubes, mainly chlorine and alkali metal driven.

The economic assumptions are a plant lifetime of a minimum 40 years with 3500 annual full load hours as in the Andasol 3 plant [39], EPC contract awarded in 2015, commissioning in 2016, 65% debt finance, a debt interest rate of 8% and 7% discount rate, see Table 1. The assumed power purchase price is AU$200/MWh which is 40% lower than the price received by the Andasol 1 plant in Spain (AU$340/MWh based on AU$/€exchange rate of 1.26 and €270/MWh [40]) and similar to a 250 MW water-cooled trough plant without storage [3]. The modeling includes capital and operating costs as well as annual escalation rates for inflation (3%), fuel (2%), electricity (3%) and water (4%). All investments shown are the owner's total project cost consisting of EPC price plus 9% owner's soft costs covering permits, project management, legal and finance aspects of a CSP plant. Payback periods and net present values derive from the total project and not only the EPC cost.

To provide confidence that the technical and economic modeling in this assessment is in line with reality, the water-cooled scenario 1 was modeled under Spanish conditions to meet the €300m for Andasol 2 plant investment [41], 51 ha aperture [40] and 28% gross solar to electricity efficiency [39]. Subsequently, the model was adapted to Australian conditions, which include higher cost factors for equipment (+12%) and labor (+20%), as well as air cooling with a mean maximum ambient temperature of 23.8 °C. The high labor costs are a result of the ongoing mining boom creating skilled labor shortages.

As external superheaters are not a standard Thermoflex component investment assumptions would have higher uncertainties and for this reason indicative prices were obtained from an industry partner with actual external superheater expertise [37].

Scenario 1 (air and water cooled) is the basis for all other scenarios. All models use identical DNI, weather conditions and feedwater heating arrangement.

3.2. Fuels considered

In Australia the use of biomass for biofuels has been investigated and a recent study concluded that biomass has the potential to provide a significantly greater greenhouse gas abatement when used for power generation rather than biofuels. This is due to the high carbon intensity of Australia's electricity sector [43].

Several biomass/waste fuels can be considered as a source for external superheating, including: refuse derived fuel (RDF); wood waste; wood chips; and stubble, as indicated in Table 2. However, to broaden the applicability of the concept other fuels can be considered, such as biogas or natural gas. Typically, RDF fired power plants limit steam temperatures to around 430 °C while wood waste units operate at up to 450 °C. In the past, stubble fired power stations limited steam temperatures to <430 °C due to the chlorine content of the fuel, however new alloy materials, developed for energy from waste plants, enable modern units to operate with steam temperatures of up to 540 °C, e.g., the 25 MWe Sangüesa plant in Spain [44]. Clean biomass, such as wood chips from forestry and horticulture, are suitable for steam temperatures up to 540 °C. This assessment uses the these steam temperatures in its scenarios but includes 480 °C and 510 °C scenarios for wood chips as several plants exist operating at these steam temperature levels.

3.3. Site information

The site selected for this analysis is in the Mildura region, Australia, which has a population of around 53,000 and is home to one of Australia's prime agriculture and horticulture regions. The solid fuel quantities required for external superheating for a 50 MWe parabolic trough plant, Tables 2 and 3, are available from agriculture, horticulture, forestry and urban waste streams [45]. The assumed fuel prices are shown in Table 2.

With an average annual DNI of 2198 kWh/m^2/year [46] the Mildura region has a higher DNI than Lleida in Spain, where the first CSP-biomass plant commenced operation recently [10], but is similar in regard to the agriculture and horticulture sources of biomass. Generally, the DNI levels are similar to southern Spain where there are several 50 MWe parabolic trough plants with 7.5 h storage.

In addition to the good solar and biomass resources Mildura is in the state of Victoria, which has one of the highest retail electricity prices in Australia [47]. This maximises plant revenue and was another criterion for selecting this site. The electricity could be consumed locally but also exported via existing transmission lines into the national electricity market.

The ambient temperatures used in this modeling derive from measurements at Mildura Airport by the Bureau of Meteorology Australia[3] and DNI data from the Thermoflex database.

Water is a scarce commodity in the region and a power plant would compete with other uses, such as irrigation water. Therefore air-cooling is the preferred option to minimise water consumption but water-cooling has also been investigated in this study.

4. Results

To provide a comprehensive assessment the different scenarios are analysed in regards to technical, economic and environmental performance as well as plant layout. Air (AC) and water-cooled (WC) concepts were modeled and the results for the different scenarios follow the same trends. The focus of the analysis is on air-cooled plants but water-cooled results are also shown.

4.1. Plant performance

With increasing steam parameters the plant solar to electricity (StE) efficiency increases significantly in the air and water cooled scenarios, as shown in Table 3. The efficiency changes shown are almost linear while the parasitic losses remain constant at around 10%. Scenarios 6 ranks best with 10% higher net solar to electricity efficiencies than a standard 50 MWe parabolic trough plant (scenarios 1). At Mildura even a 250 MWe net parabolic trough plant, such as Solana in the US, would not reach the net electric efficiency of scenario 6 AC, 27–25%, despite significant economy-of-scale benefits. The only reason to choose steam temperature of 480/510 °C (scenario 4/5) over 540 °C, when using wood chips, is the larger number of reference plants in this temperature range. Despite the same steam parameters of scenarios 6 (wood) and 7 (stubble) the stubble plant's cycle efficiency is slightly lower due to higher flue gas temperature at the stack (160 °C compared to 120 °C), which is caused by the higher chlorine content in fuel.

The efficiency difference between water and air cooling is 2.5%. This is lower than the 5% indicated in other studies [48] but is considered realistic as cooling water temperatures from the Murray

[3] www.bom.gov.au/climate/averages/tables/cw_076031.shtml.

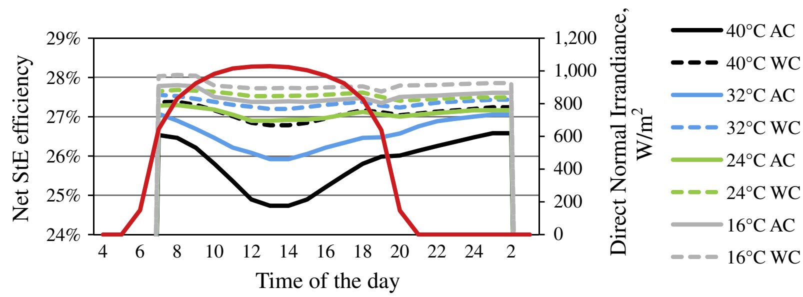

Fig. 3. Ambient temperature effect on air and water cooled scenarios 6 over a period of 24 h.

River can reach 23 °C and because the AC scenarios are optimised for the high ambient temperatures in the Mildura region.

To increase the steam parameters larger biomass quantities are required, reaching almost 50,000 t/a in scenarios 6 compared to only 14,300 t/a for scenarios 2. The additional use is justified as it results in higher overall plant efficiencies. The use of relatively small biomass quantities, such as 50,000 t/a, is beneficial as its use in a small standalone biomass plant, fuel sufficient for a 4 MWe capacity when assuming 8000 h operation/a, would have an inherently lower gross efficiency of maximum 24%. Using the 50,000 t/a wood chips in a scenario 6 AC plant generates 47.7 GWh compared to 31.3 GWh in a standalone biomass plant, an increase of 52%. The benefits of using smaller biomass quantities are even stronger, up to 80% more MWh/year, as efficiencies fall rapidly at plant capacities of 2.5 MWe (scenarios 4) or only 1.2 MWe (scenarios 2). Considering a scenario 1 plant and increasing the temperature/pressure of the same steam flow from 380 °C/100 bar to 540 °C/130 bar would increase the 50 MWe plant capacity to 55 MWe while only marginally increasing the investment for the external superheater, AU$11m or AU$2.2m/MWe. For these reasons the use of biomass for external superheating of "low" temperature steam sources, including but not limited to parabolic trough plants using thermal oil, should be encouraged even though this is likely to be a niche market.

The high temperature flue gas leaving the external superheater at 395 °C contains sufficient energy to further preheat the boiler feedwater by 13 °C, +6% compared to scenario 1, and preheat combustion air from ambient temperature to 260 °C.

Ambient temperatures in the Mildura region vary significantly, with a minimum mean temperature of 10.3 °C and a mean maximum temperature of 23.8 °C. It is not uncommon that temperatures reach/exceed 40 °C for a few consecutive days [49] and 66 days/year above 30 °C is a statistical average. These temperature changes particularly affect the efficiency of the AC scenarios (11% difference between 16 °C and 40 °C) while the WC scenarios remain more stable (5% difference between 16 °C and 40 °C), as shown in Fig. 3. This equals a capacity loss of 5.7 MWe (AC) and 2.6 MWe (WC).

4.2. Economic analysis

Air-cooling increases plant investment by an average of 4.4%, which is in line with expectations and previous studies [48]. The AU$411m investment for scenario 1 AC is slightly higher than other studies indicate for a 50 MWe parabolic trough with 7.5 h thermal storage [3]. The difference derives from particularly high labor costs in Australia, the inclusion of the 9% owner's soft costs and allowance for exchange rate fluctuations.

As with plant performance the scenarios 6 perform best, WC better than AC, in regards to investment, payback net present value (NPV) and internal rate of return on investment (IRR), as shown in Table 4. The investment cost reductions reach 23.5% when comparing scenarios 1 AC with 6 AC. This is significant considering that these reductions are possible today and not in 2020 at which time cost reductions of 17–40% are expected through continuous deployment and plant optimisation [3,5,6]. By increasing plant efficiency the specific investment of scenario 6 AC, AU$6.3m/MWe, is lower than the economy-of-scale cost reduction potential a 250 MWe parabolic trough plant on this site would offer, AU$6.5m/MWe. The reason for this is the specific solar field size reduction, m^2/MWe.

The investment reductions as well as NPV and IRR increases are almost linear and the only exceptions are scenarios 6 and 7, which have identical steam parameters. The investments of scenario 7 plants are marginally higher, 1%, due to the use of stubble which require higher quality alloys in the external superheater and higher temperature resistant baghouse and flue gas ducting, due to the different fuel composition. The slightly higher investment and fuel cost accordingly result in a lower payback, NPV and IRR.

The benefits of external superheating reflect well in the NPV and IRR which improve by 42% (NPV) from scenarios 1 AC to 6 AC and 18% (IRR) respectively. CSP plant costs are strongly affected by financing cost and reducing CapEx improves the NPV significantly despite additional costs for the biomass supply over the plant's lifetime.

The fuel price does not affect the economic viability as much as expected as doubling the fuel price in scenario 6 AC only reduces the NPV to AU$147m, see Fig. 4. The water price is even less relevant for the economic viability as doubling the price reduces the NPV of the WC scenarios by less than 0.1%. The most significant impact results from changes in the electricity price, as shown in Fig. 4, in which a 15% increase from AU$200/MWh to AU$230/MWh, raises the NPV of scenario 6 AC 43%, from AU$164m to AU$235m.

A risk to the plant economic viability, in particular for air cooled CSP plants, is the significant mean minimum and maximum ambient temperature difference of 13.5 °C in the Mildura region. Expectations of rising global average temperatures with longer and more frequent "heat wave" periods requires a design that, despite higher investment, has a sufficiently sized condenser to ensure maximum plant performance. With the current price of cooling water being relatively low but supply competition with other users a wet/dry hybrid cooling concept could be considered using water only during above 30 °C ambient temperature days.

Having the same plant capacity and thermal storage arrangement as the Andasol installations in Spain it would be expected to create the same employment of 40 annual operation and maintenance jobs [40]. Assuming that the direct and indirect employment for the external superheater operation, supply chain and fuel transport is similar to a 5 MWe biomass plant [50] the external superheater concept could create up to 30 additional full-time equivalent jobs, 11 direct and 19 indirect. This is significant for a rural region that predominantly relies on agriculture and tourism for employment creation.

Table 4
Economic comparison.

Scenario	Total plant investment (mAU$)	Specific plant investment (AU$/MW)	Specific cost reduction to scenario 1 (%)	Years payback	Net present value (mAU$)	IRR (%)
1 AC	411	8.2		15.1	116	8.6
1 WC	392	7.9		14.6	132	9.0
2 AC	384	7.7	6.7	14.5	135	9.1
2 WC	366	7.3	6.7	14.0	149	9.4
3 AC	371	7.4	14.3	14.3	139	9.2
3 WC	353	7.1	10.0	13.8	154	9.6
4 AC	348	7.0	15.4	13.9	148	9.5
4 WC	335	6.7	14.8	13.4	160	9.8
5 AC	333	6.7	19.1	13.5	156	9.8
5 WC	320	6.4	18.4	13.1	167	10.1
6 AC	315	6.3	23.5	13.1	164	10.1
6 WC	305	6.1	22.2	12.8	175	10.4
7 AC	318	6.4	22.9	13.3	160	10.0
7 WC	309	6.2	21.3	13.0	166	10.2

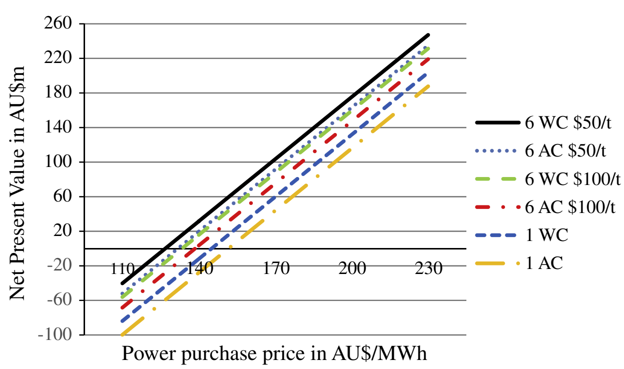

Fig. 4. Power purchase and fuel price impact on the net present value of scenarios 1 and 6.

4.3. Environmental performance

All WC scenarios perform better than AC in regards to technical and economic data but when considering the environmental impact the significant cooling water demand is a disadvantage in a region that requires water for existing agriculture and horticulture. Increasing the plant efficiency reduces the full-load cooling water requirements from 3.1 m^3/MWh (scenario 1 WC) to 2.5 m^3/MWh (scenario 6 WC) but that still adds up to 440 Ml/year, see Table 5. AC systems require ca. 90% less water with only mirror washing and blowdown being relevant consumers.

The solar field footprint decreases significantly from scenario 1 AC to 6 AC, −34%, but the difference between the individual AC/WC scenarios is with 3.5% significantly smaller, see Table 5. Increasing land use efficiency from 3.6 ha/MW to 2.4 ha/MW, scenario 1 AC to 6 AC, has economic benefits but these are limited due to relatively low land prices in the Mildura region.

The specific land use efficiencies of all AC/WC external superheater scenarios is better than the 3.1 ha/MW (WC) and 3.3 ha/MW (AC) required for a 250 MWe plant with 7.5 h of thermal storage on this site.

Despite all scenarios having the same annual electricity output of 175 GWh their greenhouse gas abatement potential varies slightly due to the different biomass harvest and transport emissions. Scenario 1 plants could abate up to 147,200 t CO_2/year (based on the 2010 Australian generation mix with a carbon intensity of 841 kg CO_2/MWh [51]) while scenario 7 plants (stubble) could abate up to 146.200 t CO_2/year (25 kg CO_2/t for 50 km transport) and scenario 6 plants (wood waste) up to 144,500 t CO_2/year (54 kg CO_2/t for 50 km transport) [43]. The slightly lower greenhouse gas abatement potential caused by biomass harvest and transport emissions is insignificant compared to the CapEx reduction potential.

4.4. Plant layout

The layout of the power island does not change in the different scenarios with the steam turbine, heat exchangers, molten salt tanks, condenser, biomass fuel storage, external superheaters, flue gas cleaning with stack, control room and auxiliaries arranged in the centre of the solar field. The most obvious changes to a standard parabolic trough plant are the solar field size reduction of up to 34% and the addition of the two external superheaters with fuel storage. Fig. 5 visualises the impact of the different AC scenarios on the overall plant footprint and highlights the main components.

Due to more frequent truck movements to supply the external superheaters with fuel a wider than usual access road is required including a spacious turning point in front of the fuel storage. Placing the fuel storage outside the solar field and installing long conveyers to transport the fuel to the external superheaters is not recommended as conveyers are a weak point in biomass plants, e.g. plant shutdown due to blockages.

5. Regions for technology implementation

Compared to standalone CSP plants the global potential for CSP-biomass hybrids is lower as only some regions worldwide have both energy sources in sufficiently high abundance. However, these sites have the potential to realise CSP plants today at costs expected in 2020, therewith fast-tracking CSP deployment and potentially avoiding the lock-in of future greenhouse gas emissions from new fossil plants.

When overlaying maps with the global annual DNI [52] and the overall index of land suitability for cultivation [53] several locations in DNI areas >1800 kWh/m^2/year seem principally suitable for CSP-biomass hybrids in Australia, Asia, China, India, Africa, southern Europe as well as south, central and north America, see Fig. 6. A minimum DNI of >1800 kWh/m^2/year is chosen as this is the DNI level of the 22.5 MWe Termosolar Borges plant site. To avoid competition with food production only areas with a land suitability index of 0.6–1 are considered as these areas could grow biomass for energy purposes in parallel with food production. This

Table 5
Water and land use comparison.

Scenario	Solar field and power block footprint (ha)	Land use efficiency (ha/MW)	Cooling water consumption (Ml/year)
1 AC	179	3.6	
1 WC	169	3.4	537
2 AC	157	3.1	
2 WC	151	3.0	504
3 AC	147	2.9	
3 WC	143	2.9	491
4 AC	139	2.8	
4 WC	134	2.7	477
5 AC	126	2.5	
5 WC	124	2.5	458
6 AC	119	2.4	
6 WC	116	2.3	440
7 AC	119	2.4	
7 WC	116	2.3	441

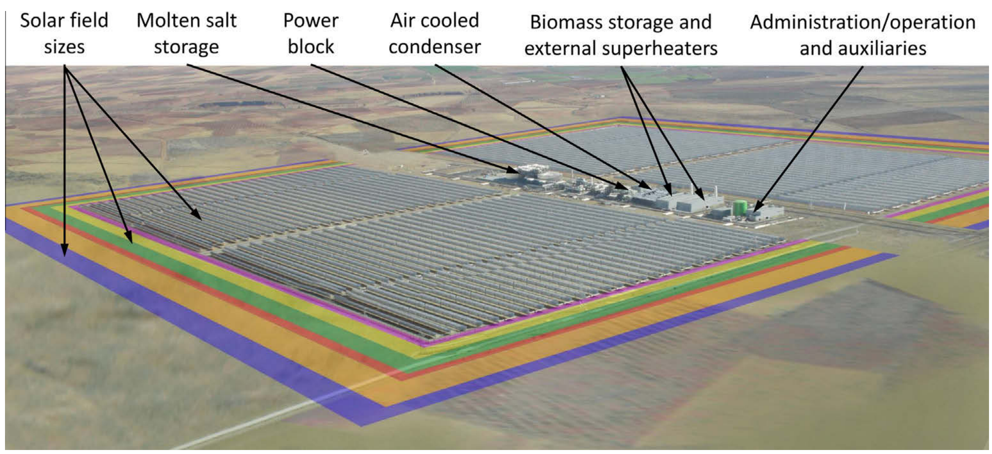

Fig. 5. Photomontage comparing the impact of scenarios 1–7 AC on the footprint of a 50 MWe parabolic trough plant with 7.5 h thermal storage; scenario 1 = blue, scenario 2 = orange, scenario 3 = red, scenario 4 = green, scenario 5 = yellow and scenario 6 and 7 = purple border around solar field. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

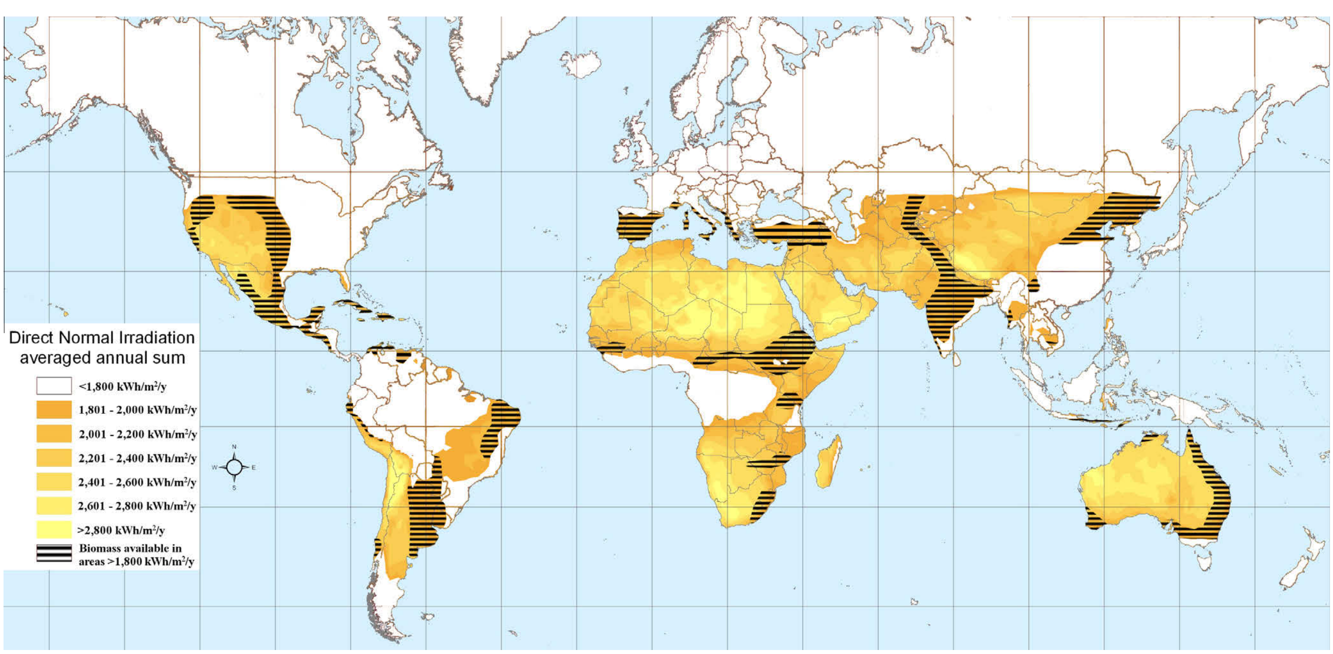

Fig. 6. Potential regions for CSP-biomass hybrids plants worldwide.

is achieved by using agriculture residues, such as straw, and agroforestry materials, such as wind breaks, or urban wood waste streams, such as construction and demolition timber. Identifying the global potential for CSP-biomass hybrid plants would require detailed geospatial mapping including multiple constraints, such as urbanisation, alternative land uses or land clearing limitations, which is not part of this paper but of interest for future research. This paper only selects some example locations from Fig. 6 to provide a high level overview.

According to a recent bioelectricity assessment [45] Australia has existing biomass resources in suitable DNI regions: in Queensland, including 2.6 mt of bagasse around Mackay; in New South Wales, including 1.9 mt of stubble around Griffith; in Victoria, including 0.7 mt stubble around Mildura; and in South Australia, including 1 mt stubble west of Port Augusta. With <50,000 t/a biomass required to externally superheat the steam of a 50 MWe CSP plant a fraction of the sites would be sufficient to implement several hundred MWe capacity. This is a significant potential in a traditionally low cost electricity country where stand-alone CSP plants struggle despite some significant government programs. As an example of the difficulty of stand-alone CSP plants competing the recently abandoned 250 MWe SolarDawn project had AU$464m of government funds allocated out of a total investment of AU$1.2b [54]. However, lower cost CSP-fossil fuel hybrid plants are being built, such as Kogan Creek [55] or Liddell [7]. External superheating with biomass could accelerate CSP deployment without fossil fuels and one such plant is being investigated in Queensland [24,56].

Further promising potential exists in California, USA), where several biomass plants operate [57] in suitable DNI areas and a 107 MWe CSP-biomass hybrid plant was already proposed [23]. Further potential exist on the western end of the wheat belt where stubble could be used for external superheating.

Similarly, Mexico, Brazil and Argentina have suitable sites for CSP-biomass hybrids as do some parts of South Africa and Ethiopia, however competition with land required for food production has to be considered very carefully in these regions. Many of these countries have weak electricity grids where smaller CSP-biomass hybrid plants could provide network benefits. Also industrial and off-grid CSP applications are relevant and present a future growth market [58]. Smaller plant capacities result in a higher specific investment and the hybridisation with biomass can help offset some of the specifically higher cost while increasing the plant's capacity factor.

In Europe the first CSP-biomass hybrid plant already commenced operation in Spain [10] and further sites could be considered in Spain but also southern France, Italy, Croatia, Greece and Turkey. In Asia, India and China seem to have the most suitable locations for CSP-biomass hybrids with large areas where high DNI and land suitability for cultivation overlap. With many of these areas being remote distributed CSP-biomass plants, similar to South America and Africa, provide promising applications.

6. Discussion

When considering an external superheater concept a few points have to be considered very carefully to ensure reliable plant operation. Starting with the fuel supply larger roads are required to accommodate the more frequent truck movements. Increased dust particles are likely from these truck movements and on-site fuel processing but these can be countered with paved roads, covering the freight and enclosed fuel processing equipment. The fuel storage should have a capacity for 4 days full-load operation and needs to be kept under negative pressure using the air as combustion air for the external superheaters.

The external superheaters require a special design to ensure that the temperatures in the furnace remain well below 1000 °C to avoid high-temperature corrosion and ash fusion issues. Furthermore refractory in the furnace should be kept to a minimum as this limits start-up times. However, solutions for this exist such as a water cooled furnace. The material selection is crucial, particularly for the superheaters but also for economiser and air heaters, to reduce plant down-time and maintenance. As the external superheaters need to start/stop/cycle frequently a fluidised bed is a suitable firing system as it operates well at low part-loads. To ensure quick start-up and back-up, in case of biomass supply problems, 100% capacity natural gas burners are required. Fuel supply issues, such as conveyer blockages, are common in biomass plants and the gas back-up would ensure continuous operations. Similarly, two external superheaters are suggested to provide redundancy.

Gasification systems firing producer gas in the external superheaters are worth considering as the technology retains a large ash fraction, due to low gas velocities in the gasifiers, which limits high-temperature corrosion and ash fusion issues in the external superheater. Several plants operate successfully with single fuel references reaching steam temperature of 525 °C [37].

Biomass considered for use in external superheaters should derive from the vicinity of the plant. The low calorific value of biomass does not justify, economically and environmentally, transport distances of more than 50 km unless the fuel is converted to pellets or briquettes on the harvest site. Therefore regions with strong agriculture, horticulture or forestry are prime candidates for the external superheater concept. In addition to the fuels outlined in Table 2 further materials can be considered broadening the applicability of the external superheater concept. Traditional biomass includes olive pits, nut shells, etc. but such material is very location specific and therefore of limited availability. An innovative potential feedstock is algae which require significantly less land to grow and grows quickly. Algae were not considered in this assessment as there are no production facilities at the required scale available yet. Furthermore biogas and landfill gas as well as other gaseous or liquid fuels are suitable for external superheaters but have to be analysed carefully to avoid high-temperature corrosion issues. With the biomass quantities and calorific values given in this paper it is possible to calculate the thermal input and therefore the quantities of other fuels than the ones outlined in Table 2.

A well organised fuel supply infrastructure is very important to ensure material availability at all times. This requires a close operation with ideally more than one supplier and long-term fuel supply contracts. The plant should not be designed to the maximum biomass availability in the region but a conservative estimate as seasonal changes can affect the biomass harvest significantly.

7. Conclusions

Externally superheating the live steam of a parabolic trough plant with biomass has the potential to increase the peak solar to electricity efficiency by up to 10.5%, thereby pushing it above 30% (gross) and into the spheres of modern solar tower plants. Other fuels are suitable for external superheating too but the use of biomass allows fully renewable electricity generation. It needs to be acknowledged that suitable locations for CSP-biomass hybrid plants are limited but as outlined in the paper even small biomass quantities, such as those <15,000 t/year, can provide material benefits.

The increased efficiency can lead to immediate CSP cost reductions of up to 23.5%, particularly driven by the smaller solar field, and a specific plant investment of only AU$6.1m/MWe for a 50 MWe parabolic trough plant with 7.5 h thermal storage. This is significant and has the potential to strengthen CSP in the increasingly competitive electricity market. Despite the CSP-biomass hybrid potential being limited the concept offers the installation of CSP systems in a variety of locations worldwide at lower cost. This would advance the industry along the learning curve while parallel research and development on new working fluids, optimised receivers, etc. provides the technologies for more competitive CSP power generation in the future.

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4.4.3 Future CSP–EfB and CSP–EfW hybrid plants

The CSP, EfB and EfW technologies analysed in the previous sections represent the current state-of-the-art technologies and, like other reports, this research assumes that these remain the dominant ones for the foreseeable future. However, new CSP technologies, and new thermochemical conversion technologies for solid fuels and materials will emerge over time and affect the cycle efficiency and cost of future CSP hybrid plants and of Rankine cycle power plants in general. New thermochemical conversion technologies, such as advanced gasification, paired with new tube materials, such as advanced copper-nickel alloys and ceramics, would allow significantly higher steam parameters than the current state-of-the-art 540 °C at 130 bar without significant high-temperature corrosion and ash fusion problems on the boiler's superheater tube banks. Also, transdisciplinary research introducing ideas into the engineering field from research in biology, such as algae as an energy feedstock, or ideas from nanotechnology, such as nano-coatings to improve component reliability, is likely to change the current technology palette significantly.

The impact of higher steam parameters of up to 700 °C and 350 bar on the efficiency of current Rankine cycle systems is relatively easy to estimate and Figure 32 provides an example for a 100 MWe air-cooled solar tower-biomass combustion-type hybrid plant at Mildura, Australia. However, the efficiency curve provided is only indicative as innovations in turbines, condensers, auxiliary equipment and working fluids are likely but predicting their combined impact on plant efficiency is difficult. Therefore, the future efficiency of such systems could be significantly higher than shown in the example.

Similarly, high-level cycle efficiency estimates of future hybrid plants using CSP to gasify biomass feedstocks, as described in Section 2.5.3.2, are possible. Assuming that such plants would consist of a Brayton cycle with a bottoming Rankine cycle system their net efficiency could reach up to 60% and potentially more if suitable fuel cells were available. However, these estimates again assume the introduction of future innovations, including in gasification efficiencies, syngas cleaning, syngas compression, and improvements to gas turbines and the aforementioned Rankine cycle.

Generally, higher Rankine cycle efficiencies in CSP plants lead to lower specific plant costs due to the solar field size reduction. This is relevant as the solar field is the most expensive plant component (IRENA 2012). However, the combined cost impact of higher efficiency technologies and learning from technology deployment is a challenge as various factors, such as cost trajectories for new materials, are inherently uncertain. Figure 32 provides an example of a 100 MWe CSP–EfB hybrid plant at Mildura. It is apparent that the range of possible cost impacts widens with rising steam parameters. At current material costs, a plant with live steam parameters of 700 °C and 350 bar would be 30% more expensive than a standard power plant, but assuming future cost reductions for currently exotic materials, such as Alloy 740 and 740H (Patel et al. 2013), through deployment and ongoing R&D has the potential to lower future plant cost by 10%. Additionally, ongoing learnings from technology deployment, new construction and finance methods, supply chain improvements, and R&D could contribute to further CSP cost reductions of up to 40% by 2020 (IRENA 2012).

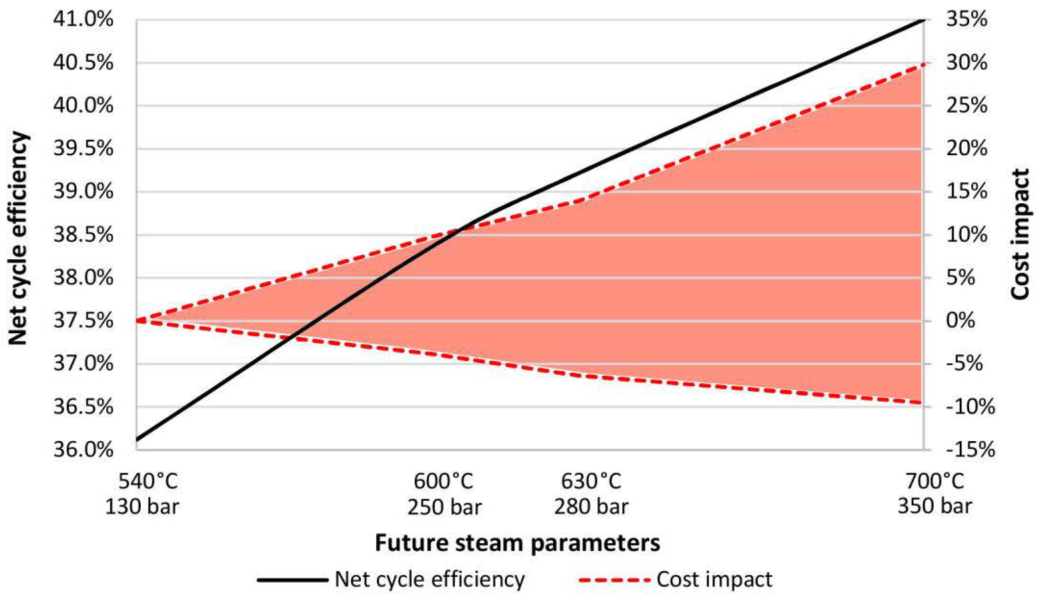

Figure 32: Potential efficiency increase (black line) and range of cost impact (red dotted lines) based on future steam parameters for a 100 MWe (net) CSP–EfB hybrid plant with air cooling at Mildura, Australia[12]

Ongoing global R&D will further improve the efficiency of future power plants and in light of the multitude of factors which can affect cost, a reliable estimate of CSP–EfB and CSP–EfW hybrid plant efficiencies and costs over the next several decades is a complicated task and the large number of uncertainties make any prediction very unreliable. This one of the reasons why this research project concentrated on the use of current technologies that have a maturity that is sufficiently high to obtain finance. Obtaining finance is crucial for near-term CSP deployment in Australia and elsewhere. Technology trajectories are required to convince governments and financiers of the benefits a technology such as CSP can provide. However, basing one's investment decisions on predictions about the future efficiency and cost of CSP decades ahead might be an unwise use of resources as competing

[12] Data derived from Thermoflex, version 23, modelling based on an altitude of 50 m, ambient temperature of 25 °C, single steam reheating, air-cooling and a design DNI of 800 W/m^2.

technologies, such as PV with battery storage, might mature more quickly than currently expected, thereby making CSP commercially uncompetitive. Long-term predictions can also raise false expectations and cause a slowdown in near-term technology deployment as investors and other stakeholders delay committing to projects on the expectation that low-cost renewable energy technologies will become available in the future. Hence, a fine balance between the learning opportunities derived from technology deployment and further R&D is required, and technology trajectories for the next decade should be based on trends that can be observed currently, such as current R&D efforts in thermochemical conversion technologies and materials.

4.5 Implementation barriers

Renewable sources contributed 10% of Australia's total electricity generation in 2010–11 (Bureau of Resources and Energy Economics 2013). This is significantly lower than the global average of 20% (International Energy Agency 2013) despite several excellent resources, such as solar irradiance, plentiful wind and geothermal sites. Considering that hydro is the dominant source of renewable electricity in Australia, and that most hydro installations have been in operation for decades it becomes apparent that growth in new renewable electricity generation has been small and therefore a set of barriers must be limiting its uptake.

Several studies have identified renewable energy barriers worldwide (Moomaw et al. 2011; Painuly 2001; Verbruggen et al. 2010) and for Australia (Effendi & Courvisanos 2012; Martin & Rice 2012) but this study focuses specifically on CSP-only and hybrid plants. Multiple barrier definitions are available and this thesis uses the definition from Wilkins (2002) which states that barriers are "*factors that impede the adoption of a new technology*" (Wilkins 2002, page 120). At times barriers are also referred to as market failures (Wilkins 2002), but this terminology refers more specifically to a lower market penetration of a certain technology than would be most economically efficient (Gillingham & Sweeney 2012). Barriers to renewable energy, as well as to energy efficiency and low carbon technologies, can have a social, technical, environmental, economic or policy background. They can cover more than one of the aforementioned categories and are often interrelated. For example, policy uncertainty or technical maturity influence finance costs. To accelerate renewable energy implementation a clear understanding of the current barriers is essential. Some barriers (such as higher LCOE for renewables due to the failure to consider externalities in the pricing of electricity from fossil fuels) are universal. Other (such as policy settings) are country-specific.

Changing the current fossil fuel dominated electricity market to a more sustainable one is crucial to limit anthropogenic climate change and its negative effects on Australia (Reisinger et al. 2014). Renewable energy technologies can achieve this and recent studies investigating 100% renewable electricity scenarios for Australia have concluded that CSP is an important technology for achieving this goal (Elliston, Diesendorf & MacGill 2012; Elliston, MacGill & Diesendorf 2013; Wright et al. 2011) but currently there are no CSP-only plants in Australia. Two significant projects were offered state/federal funding: AU$ 464m for the 250 MWe SolarDawn project and AU$ 60m for the 40 MWe SolarOasis project, had their offers withdrawn as neither project developer was able to secure the remaining funding they needed (Edwards 2013; Kelly 2012). CSP hybrids have been more successful:

one plant is already in operation at the Liddell power station (Novatec Solar GmbH 2012b), another one is under construction at the Kogan Creek power station (CS Energy 2011), and some, such as Collinsville and Swanbank, are being investigated at different levels of detail (Australian Renewable Energy Agency 2013a; Peterseim et al. 2012b). From these observations it can be concluded that hybrids seem to have lower implementation barriers and this study aims to identify the key barriers for CSP hybrid plants in Australia and to ascertain the extent to which they differ from barriers for CSP-only plants. This knowledge is needed to make predictions about the potential to accelerate CSP uptake in the current Australian environment.

The development, design, construction and operation of CSP plants and power plants in general requires people with various skills, and some of these people will have different views on specific aspects of a project. For example researchers, engineers and financiers are likely to have different perspectives on risks. To take account of these variations in perspective, people with different backgrounds were invited to the workshop, including researchers, plant owners/operators, consultants, technology providers and government representatives. Plant financiers did not attend but power plant owners/operators have financial expertise. The participant breakdown is shown in Figure 33 and the results which follow are based on their individual ratings.

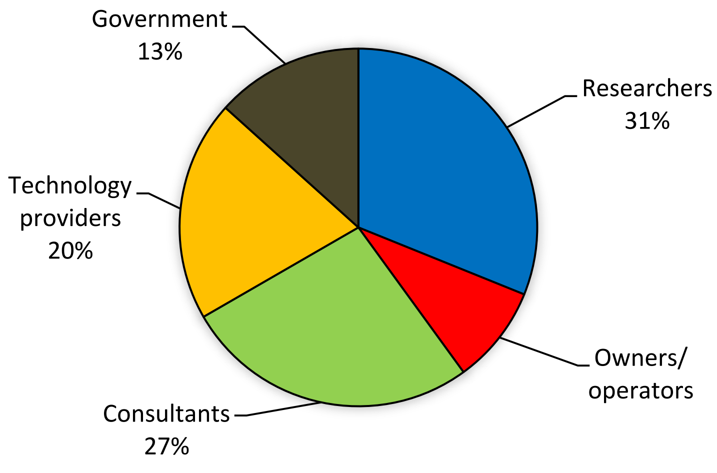

Figure 33: Participant breakdown for implementation barrier ranking

4.5.1 Significant Australian barriers to CSP

Implementation barriers are multi-faceted and cover a variety of aspects, such as social, technical, environmental, economic and policy, and they often influence each other. A clear understanding of the different barriers is required to accelerate CSP-only and hybrid implementation in Australia and this assessment considers a range of barrier categories and individual barriers. The same barriers are likely to exist in different markets worldwide.

4.5.1.1 Social barriers

Several social barriers exist for CSP installations and this assessment compares eight, five of them were presented to the workshop and three were added by the workshop participants.

Consumer fear of higher energy prices: Since2008 years electricity prices in Australia increased significantly (see Figure 5 on page 8) and naturally people are concerned with the higher cost of living, not only the cost of electricity. However, the reasons for the price increases have to be communicated transparently. In Australia, for example, 50% of the price increases were driven by significant investments in distribution and transmission infrastructure, while the large-scale renewable energy target is responsible for 7% of the increase (Australian Energy Market Commission 2011). Information about the historic and current electricity price composition, as well as future predictions, is available but its transparent dissemination is key to gaining, maintaining and increasing public support for renewable energy.

Lack of confidence in the technology: This barrier was added by workshop participants. In Australia the CSP track record is poor, with several high profile projects being abandoned in the four three years, such as the 250 MWe SolarDawn (Kelly 2012) project, the 40 MWe SolarOasis project (Edwards 2013) and the 10 MWe Cloncurry project (Michael 2010). On the other hand PV projects, such as the 10 MWe Greenough River Solar Farm in Western Australia (Verve Energy 2013), the 102 MWe Nyngan project and the 53 MW Broken Hill project in New South Wales, have gone ahead (Hobson & Winsbury 2013). Only one small 18.3 MWth CSP hybrid plant is currently in operation at the coal fired Liddell power station (AREVA Solar 2012b; Novatec Solar GmbH 2012a) with a significantly larger 44 MWe equivalent project under construction at the Kogan Creek power station (CS Energy 2011). However, worldwide around 50 commercial CSP plants with capacities from 5 to 280 MWe are operating successfully and these provide confidence that the technology would also work in Australia.

Lack of accessible data: This barrier was added by workshop participants. A variety of data is available for CSP systems in the public domain, especially in journal and conference publications, but some of them require subscriptions and are therefore not easily accessible for everyone who is interested in this field. However, several easily accessible and high quality reports with global and country-specific information exist on the internet – for example on the International Renewable Energy Agency's website (IRENA 2012) and on the Australian Solar Thermal Electricity Association's website (Lovegrove et al. 2012).

Lack of, or poor quality of, information, education and awareness: Information about the need to move to a low carbon future and the provision of this information to the general public is vital for implementing renewable energy and energy efficiency systems. A vast body of literature is available in the public domain but not all of it can be understood by people who do not work in the energy sector. On the other hand the complexity of the field means that there is a limit how much the information can be simplified without neglecting relevant facts. Education programs can increase awareness about renewable energy and are available through several institutions, ranging from day care centres, schools, universities, private and public organisations, to internet-based sources. Providing information on overseas experiences with renewable energy plants gives people actual information rather than estimates and this not only raises awareness of the technologies but also influences other social barriers, such as technology acceptance, fear of electricity prices and fear of change. Similarly, Australian case studies would help familiarise the community with the technology.

Fear of change: This barrier was added by workshop participants. The current centralised power generation regime in Australia is long established and therefore well understood. Many renewable energy and distributed generation plants challenge this current regime and introduce not only new generation assets, small base-load and intermittent generators, but also new ways to transport energy, such as smart grids. These changes can cause uncertainty for individuals, organisations and communities in regards to employment, new infrastructure, and cost of living. The resistance to technical change in organisations has been investigated and some observers have concluded that communication of the changes and their benefits is a key to avoiding speculation, half-truths and uncertainty (Cunningham, Farquharson & Hull 1991).

Technology acceptance: Some renewable energy technologies face opposition for a variety of real or perceived reasons. In the case of wind farms this includes concerns over low-frequency noise, landscape change and visual impact on amenity, and merely providing facts does not solve the problem as people make judgments based on their own perspectives and circumstances. However, the negativity displayed in the media and by some interest groups towards certain technologies such as wind can be quite different to the actual level of community acceptance (Hall, Ashworth & Shaw 2012). Extensive community engagement is required to understand and address local concerns and increase technology acceptance. Due to the limited reference plants and hence the limited local experience with CSP, the technology can encounter similar acceptance problems and lawsuits have already been brought against project developers in the USA claiming that "*the impacts to Native American culture and the environment are extraordinary*" (Woody 2011). Some lawsuits have successfully obtained injunctions halting CSP projects and have even caused developers to withdraw their proposals.

Impact on visual amenity: This barrier was added by workshop participants. Visual impact is not only an environmental barrier, see 4.5.1.3, but also has social implications as it clearly shows the presence of a renewable energy plant and reminds people constantly about this facility. It needs to be mentioned though that parabolic trough, Fresnel and dish plants do not have tall structures and therefore they involve a minimal visual impact. Solar tower systems on the other hand are, due to tower heights of over 100 m, clearly visible from the distance. People's perceptions of the landscape change and the visual impact on amenity varies significantly and the wind industry provides a good example where responses to the presence of wind turbines range from enthusiastic acceptance to strong rejection. In Queensland one solar tower project was withdrawn in 2010 due to solar glare issues (Michael 2010), which shows that site selection and technology selection have to be considered carefully.

Consumer lack of interest in renewable energy: Uncertainty about the state of the global economy and about the future prosperity of individual countries can cause consumer priorities to shift, with the result that employment and cost of living concerns may rank higher than concerns about climate change. A recent USA survey found that the economy and job creation are the concerns that rank highest for most people, with environmental protection ranking 12th and climate change ranking only 21st (Dimock, Doherty & Kohut 2013). While in 2013 the majority of Americans (52%) believed environmental protection should be a priority the issue was considered more significant in 2001 (63%), before the global economic crisis. Similarly, in Australia employment concerns come to the fore when people discuss renewable energy, climate change and carbon pricing, particularly in fossil fuel dominated areas, such as the Latrobe Valley in Victoria (Carey 2011). Therefore, short-term public concerns have to be addressed carefully when communicating the scientifically agreed need for renewable energy implementation and its socio-economic benefits.

4.5.1.2 Technical barriers

Technical barriers cover a wide field ranging from network access to technology maturity and codes and standards. This assessment compares seven barriers, six of which were prepared for the workshop and one of which was added by the workshop participants.

Network access, capacity and availability: The Australian transmission network is designed to transport electricity from centralised facilities to consumers and does not necessarily cater for the addition of many distributed generators located close to demand centres. The connection costs for new CSP plants without TES varies from 8% to 11% of the total investment (Rutovitz et al., 2013) which makes it a high cost item for project developers. However, costs can be lowered by adding CSP plants to grid-constrained locations where they can defer or even remove the need for network augmentation (Rutovitz et al., 2013). In addition to connection costs, network availability is a constraint with almost no transmission lines for utility-scale plants in the best direct normal irradiance regions of Australia (Lovegrove et al. 2012). However, smaller systems, of less than 30 MWe, have better access to the existing network as they can connect to lower capacity transmission lines (Lovegrove et al. 2012).

Technology maturity: Compared to other renewable and fossil fuel technologies the estimated global CSP deployment of 4 GWe in 2013 (International Energy Agency 2013) shows that the technology is not as widely deployed as other renewable alternatives. However, significant differences exist between the different CSP technologies, and parabolic trough plants are the most mature with commercial operating experience since the 1980s. Solar towers are maturing quickly with various 20–130 MWe plants in operation (BrightSource Energy Inc. 2013; García & Roberto Calvo 2012). Also, Fresnel systems operate successfully at 30MWe scales (Novatec Solar GmbH 2012c) and a 2x 125 MWe unit is under construction (AREVA Solar 2012a). The continuous operation and commissioning of further plants will provide better information about tower and Fresnel systems and will enable a more realistic technology comparison based on actual performance rather than modelled data.

Lack of accessible technical data: This barrier was added by workshop participants. Little detailed technical data is available about the operational performance of individual CSP plants as this information is regarded as commercially sensitive by the plant owners. A multitude of assessments have investigated the technical and economic performances of CSP plants and sophisticated software tools exist for project developers to model plant performance at specific locations, such as the System Advisory Model by NREL[13] or Thermoflex by Thermoflow. With no CSP-only plants in Australia all information is based on models and actual detailed information, including compliance with Australian standards, is not available.

Technology complexity: Due to the spread of CSP systems over large areas, the significant number of reflectors, and the use of TES equipment the technology is more complex than

[13] https://sam.nrel.gov, accessed 04 April 2014

current coal and gas plants, PV installations and wind generators. However, the solar field components are standardised units, the power blocks are similar to those used in other Rankine cycle plants and the TES system has been proven in many CSP references with up to 15 h full-load storage capacities (García & Roberto Calvo 2012). Also, high degrees of automation, such as solar tracking, reduce operational risk and costs.

Generation intermittency/lack of energy storage: PV and wind generators only generate electricity during times of sufficient solar irradiance and wind speed, while CSP systems can store energy during the day and shift output to higher demand times. One 20 MWe plant with 15 h TES in Spain demonstrated 24-hour operation (García & Roberto Calvo 2012), several other operational plants have 7.5 h of TES, and a new system will commence construction this year with 17.5 h thermal storage (Abengoa Solar 2014a). Having the ability to store energy and being flexible in plant size gives CSP a unique advantage as currently no other renewable technology in Australia can combine high capacity factors with utility scale. PV and wind have utility scale while biomass and geothermal plants have high capacity factors but none have both. Therefore, several studies that have investigated high penetration renewable electricity scenarios in Australia which allocate a significant future generation capacity to CSP (Elliston, Diesendorf & MacGill 2012; Wright et al. 2011).

Lack of standards and codes: The international ASME and Australian Standards cover all relevant aspects of designing a CSP plants according to local requirements, such as pressure vessel, piping and boiler codes. These codes must have already been applied to the two CSP hybrid plants in Australia and can be used for future CSP-only plants too. With little CSP expertise in Australia, approving a compliant design will take slightly longer as engineers will have to apply codes and standards to unfamiliar components. However, they are familiar with requirements for components such as pressure vessels and control systems for significantly more complex systems, such as gas processing plants, and should be able to apply this knowledge quickly.

Resource assessments/knowledge of best locations: Knowing where to build CSP plants is essential to maximise economic viability and several reports have identified various prospective regions for CSP plants across Australia. While hybrid plants are discussed in the Australian context (Evans & Peck 2011; Lovegrove et al. 2012; Meehan 2013; Peterseim et al. 2014d) few analyses have identified potential regions and specific opportunities for CSP hybrids in detail (Meehan 2013; Peterseim et al. 2014d). The combination of two or more energy sources adds another layer of complexity to site identification for hybrid plants but modern geospatial software is capable of doing this, as demonstrated by Peterseim et al. (2014b) for CSP–EfB and CSP–EfW hybrid plants.

4.5.1.3 Environmental barriers

With CSP systems having to comply with the same environmental approval processes that other generators, they too can encounter environmental barriers. This assessment considers four different barriers.

Water consumption: Typically, water is a scarce commodity in high DNI areas and a power station would compete for it with other users, such as agriculture, or it can encounter significant limitations, such as legislatively regulated minimum environmental flows. Using dry- rather than wet-cooling systems can reduce water consumption by more than 90% (Turchi et al. 2010) and modern mirror cleaning robots can significantly reduce cleaning water requirements (Novatec Solar GmbH 2011; Vicente et al. 2012), which is a small water user anyway (Turchi et al. 2010). Water scarcity is apparent in Australia as it is one of the few countries with air-cooled utility scale coal fired power plants such as the Kogan Creek power station (CS Energy 2013).

Impact on visual amenity: Typically, CSP plants are in remote locations with limited population centres, flora and fauna. The plant components for line focusing and dish systems are no higher than for other industrial facilities and only tower systems have a more significant visual impact through the tower structure itself and the highly illuminated receiver. Most other components are similar to other Rankine cycle systems. The benefit of CSP systems is that they can be located in remote locations as substitutes for power plants and fuel production systems close to urban centres. This eases visual amenity problems (EASAC 2011).

Plant footprint/land use: In comparison to other renewable developments such as biomass plants, and fossil energy systems such as coal plants, the physical footprint of a CSP power plant is significantly larger. However, this is different when one includes fuel production, such as biomass plantation and coal mining, and CSP compares well with land requirements of 17 m^2/MWh/year compared to 550 m^2/MWh/year for biomass and 60 m^2/MWh/year for coal (EASAC 2011). The plant footprint varies significantly between different CSP technologies (Müller-Steinhagen & Trieb 2004) but the generally large power plant footprint can, amongst other problems, lead to compacting of larger areas during construction, cutting dispersion routes for animals and potential isolation of regional animal populations during construction and operation (EASAC 2011). The local flora and fauna in desert and semi-desert environments needs longer to recover from disturbances and therefore careful consideration has to be given to site selection and plant construction. Several CSP projects have already been halted and withdrawn due to community concerns about the environmental impact on fragile landscapes (Woody 2011). Birds could be affected if they mistake the large reflective areas for air or water. They may sustain heat shocks or burning damage in the concentrated light beams, or they may collide with the solar tower structure. However, birds rarely collide with CSP plants. Casualties have been documented, but these are very limited with only two recorded bird deaths between 2007 and 2011 at a monitored tower plant in Spain (EASAC 2011).

Inefficient use of back-up fuels: All CSP plants have a back-up system for start-up, emergency or part-load load operation. These systems are not intended to operate over long periods and some countries limit their contribution to marginal energy inputs. Natural gas is the predominant back-up fuel and using this fuel in a modern CSP plant allows conversion efficiencies of around 40% while a combined cycle gas turbine plant can achieve 60%. The natural gas consumption in back-up systems should therefore be minimised as designated natural gas plants could generate up to 50% more electricity from the same amount of fuel. Hybrid plants with larger shares of fossil or renewable fuels take this into consideration and are designed for maximum efficiency for both types of fuels. Integrated solar combined cycle plants are an example of this.

4.5.1.4 Economic barriers

Despite significant investment increases in renewable energy systems in recent years they still face economic barriers and this assessment considers six, with five prepared for the workshop and one added by the workshop participants.

High project capital/financing cost and typically large projects: Despite significant cost reductions through CSP deployment, innovation and associated learning the specific cost is still comparatively high in Australia e.g. 100 MWe in a 2,400 kWh/m^2/year DNI location without TES AU$ 4.65/MWe and AU$ 7.35/MWe with 5h TES (Lovegrove et al. 2012). By 2020 costs could decrease by up to 40% (IRENA, 2012) but this would require continuous deployment and technological improvements. The solar tower systems that commenced operations recently, and the parabolic trough plants with molten salt will provide actual information on the economic impact of technological improvements, particularly in regards to high-temperature TES. To obtain economies-of-scale large plant capacities are required and current plant capacities reach 280 MWe, for example in the Solana plant (Abengoa Solar 2013b). The trend towards large capacities, coupled with comparatively high investments, quickly leads to hundred million or even billion dollar project budgets. Inherently, this complicates project finances and adds a risk premium. Hybrid plants have an advantage in this regard as even small capacities can be added to existing plants, such as only 9.3 MWth at the Liddell project (Novatec Solar GmbH 2012b).

Lack of financial incentives: Despite the current existence of a carbon and renewable energy certificate price in Australia there is still a cost gap for CSP plants which varies according to location from AU$ 110-115+/MWh for 50-250 MWe plants connected to the NEM and from AU$ 10-50+/MWh for 1-10 MWe plants in mini/off grid locations (Lovegrove et al. 2012). This clearly shows that in Australia further incentives are required to implement CSP systems and the lack of CSP-only plants proves this. Plants in mini/off grid locations are much closer to market viability and the lower specific investment for hybrid plants relative to CSP-only plants has resulted in two CSP-coal hybrids projects. Further incentives to stimulate deployment include feed-in tariffs, loan guarantees or government grants.

Lower cost renewable energy alternatives: Currently, other forms of renewable energy, such as wind or PV, are lower cost options with more capacity deployed and therefore more learning experience. Both technologies are further advanced and it is therefore likely that future cost reductions will be lower than for CSP, assuming continuous CSP deployment. The cost structure is different when comparing technologies based on their annual generation and dispatchability, since intermittent renewables currently rely on high cost battery storage. Considering that CSP has mature thermal storage its costs are expected to be lower than PV with battery storage in 2025 (AT Kearney & ESTELA 2010). With larger proportions of intermittent renewable energy connected to the electricity grid, dispatchable power is essential to ensure stable grid operation and this provides a price premium for technologies that can dispatch electricity during high demand times. CSP with TES can do this and various high renewable energy scenarios therefore include significant CSP contributions in the future (Elliston, Diesendorf & MacGill 2012; Wright et al. 2011).

Abundant and subsidised fossil fuel resources: Australia not only has abundant coal, gas and uranium but also solar, wind and geothermal resources. While financial incentives exist for renewable energy and were estimated to be between AU$ 317-334m in 2005-06, these were significantly lower than the AU$ 9.3–10.1b for fossil fuel energy and transport subsidies for same period (Riedy 2007). More recent information indicates that by 2011 fossil fuel subsidies increased to AU$ 12.2b with AU$ 1.1b spent on clean energy programs (Morton 2011). This development is not confined to Australia as in 2011 global fossil fuel subsidies were estimated to be US$ 523b, an increase of nearly 30% compared to 2010 and six times the support provided to renewables (International Energy Agency 2012b).

Correcting this mismatch could boost renewable deployment by providing a level playing field for all power generation technologies.

Lack of externality costing: This barrier was added by workshop participants. Currently, Australia has a carbon emission price of AU$ 24.15/t internalising some of the environmental costs incurred through the use of fossil fuels. However, recent developments aiming to abandon this mechanism (The Parliament of the Commonwealth of Australia 2013b) or linking the scheme to Europe's lower cost, AU$ 6-10/t, emission trading market (Peatling 2013) will harm the business case for renewable energy and slow project deployment.

Pre-existing investment in existing equipment and infrastructure: Companies that invested in generation infrastructure need to operate their plants for the lifetime of the plant to obtain the expected return on investment. This particularly affects recently commissioned power stations which have not amortised themselves yet, such as the 750 MWe Kogan Creek coal fired power station commissioned in 2007 (CS Energy 2013). One way to future proof such assets and reduce their environmental footprint is to retrofit or even convert them to renewable energy and the 44 MWe Kogan Creek Solar Boost project is one good example of this (CS Energy 2011). However, the majority of Australia's coal fired power station fleet was built in the 1970s and 1980s and considering a design life of 40 years these plants are about to reach/have reached the end of their design life. This provides a unique opportunity to increase renewable energy capacity significantly over the next few years but also poses a risk as the construction of new fossil plants would lock in such generation for the next decades, leading to a lower renewable energy uptake or stranded assets.

4.5.1.5 Policy barriers

Worldwide, governments try to stimulate the uptake of renewable energies and reduce carbon emissions. A variety of measures were introduced but to significantly increase private capital the right policy settings are required. This assessment considers seven barriers in the policy space. Six of them were prepared for the workshop and one was added by the workshop participants.

Renewable energy policy uncertainty: Australia has an unconditional 5% greenhouse gas reduction target for 2020 (Department of Climate Change and Energy Efficiency 2012) but the government's and opposition's strategies to reach it are different. The previous government introduced a carbon pricing mechanism (Australian Government 2011) but the newly elected one plans to repeal this mechanism and instead implement a direct action policy (Commonwealth of Australia 2013). Only some details are available about the direct action policy and adding to the current uncertainty is another review of the 45 TWh RET (Hunt & Macfarlane 2014) after it was left unchanged in 2012 (Climate Change Authority 2012). Also, there have been discussions about lowering the RET to accommodate the current decrease in annual electricity demand (Fitzgibbon 2012). Such policy uncertainty is not only an Australian problem as other countries, for example Spain, have reduced or are planning to reduce renewable energy support (Crespo 2013). This is particularly significant for CSP as Spain has been its strongest growth market in recent years (IRENA 2012).

Lack of government policy focus: Traditionally, the coal, oil and gas industries are strong in Australia and in the context of slowing economic growth individual multi-billion dollar projects might be more appealing to government decision-makers than smaller renewable energy projects. While renewable energy projects can create significant new employment (Caldés et al. 2009; Lucas et al. 2011; Wei, Patadia & Kammen 2010) these benefits have to be communicated to decision-makers to ensure that these facts are considered when policies are drafted. Schläpfer (2009) argues that:

> *policy makers in Australia appear to believe unreservedly that we can only find solutions to the technical challenges associated with fossil fuel and nuclear technologies and equally believe that we cannot find similar solutions to the technical challenges associated with renewable energy technologies* (Schläpfer 2009, p. 459).

One observation supporting a bias towards fossil fuels could be seen in the 2009–10 budget where AU$ 2b of the AU$ 3.5b clean energy initiative was allocated to carbon capture and storage, and AU$ 1.5b went to CSP demonstration projects (Australian Government 2009).

Market concentration: In Australia three energy retailers provide 75% of the electricity in the NEM which complicates power purchase agreements (PPA) and market access for small project developers (Hannam 2013). The current renewable energy target does require all retailers to provide a total of 41 TWh from renewable energy sources by 2020. This amount plus the 4 TWh allocated for small renewable energy generators would be 20% of the previously expected annual electricity generation (Climate Change Authority 2012) but there are no earlier required milestones. Not having earlier milestones poses the threat that project development efforts are being delayed towards the end of this decade. This would leave smaller developers without a viable business case for the intervening period and creates a boom and bust cycle for the industry.

Lack of coordination at the state and national levels: Different financial incentives exist at the federal and state levels in Australia, such as the current federal carbon pricing mechanism and PV feed-in tariffs in Queensland (Queensland Competition Authority 2013).

This increases project development complexity and uncertainty as state legislation can be changed more quickly than federal legislation. The incentives also vary with plant size. There are feed-in tariffs available for household PV installations (Queensland Competition Authority 2013) but there is nothing for large scale systems, such as CSP. Without continuous reviews the large scale fraction of the renewable energy target could provide a valuable incentive for CSP but the current renewable energy certificate price is insufficient.

Regulators not having sufficient familiarity with the technology: This barrier was added by workshop participants. Regulators and policy makers are very familiar with fossil fuel projects in Australia as many of them have been realised over the last five decades. However, they are significantly less experienced with renewable energy projects given that renewable energy only contributed 10% of total electricity output in 2010-11 and two thirds of this came from existing hydro assets (Bureau of Resources and Energy Economics 2013). With further renewable energy systems being deployed in the future, regulators and policy makers will gain more experience and can in the meantime draw on overseas experience in all forms of renewable energies, particularly from Spain and USA for CSP.

Complex plant compliance processes: In Australia large and small generators have to comply with similar legislations which makes the compliance costs for a GW-size plant a less significant part of the overall project budget but a more significant one for smaller renewable energy plants. In Queensland for example, renewable energy projects have to comply with the Environment Conservation and Biodiversity Conservation Act (1999), the Integrated Planning Act (1997), the Environmental Protection Act (1994), the Electricity Act (1994) and further land-use regulations and approvals (Martin & Rice 2012). All generators, including renewable energy projects, have to ensure a minimal environmental impact and need to be assessed accordingly but streamlining the process is important as compliance costs on an AU$ per MWe basis are higher for smaller plants. Queensland's 'Green Door' initiative aims to deliver this through joint state and municipal council case management teams assessing ecological, economic and community wellbeing aspects (Queensland Government 2011). Such initiatives are required to support project developers.

Lack of a skilled workforce: The Australian unemployment rate was 5.9% in January 2014 (Australian Bureau of Statistics 2014). This is comparatively low compared to other countries and with CSP plants typically being remote, their owners are likely to struggle for qualified operators as the mining industry attracts people to work in remote locations with higher wages. Training residents in high DNI urban centres, such as Roma in Queensland or Whyalla in South Australia, is key to providing qualified operators and diversifying employment opportunities in these locations. People are likely to accept a local jobs with a slightly lower remuneration rather than fly-in fly-out jobs that separate them from their families. The workforce required to design CSP plants is available in Australia even though some components, such as reflector or receiver details, would have to be designed overseas. Highly qualified process and civil engineers are available and their knowledge from power, oil and gas, and mining projects can be applied to CSP projects.

4.5.2 Rating results

The participants' ratings for the barriers for CSP-only and hybrid plants vary significantly and Figure 34 shows the results. All barriers selected were considered significant with no barrier ranked 1 (not important) and the lowest barrier ranking being 3.8 of a maximum of 9 (extremely important). While some participants rated individual barriers with the highest score of 9 no barrier reached such a high rating on average, which is why the barrier importance scale in Figure 34 ends at the rating of 8.

This section outlines the barrier ranking results, compares the individual barriers and barrier categories, and shows the rating differences between CSP-only and hybrid plants.

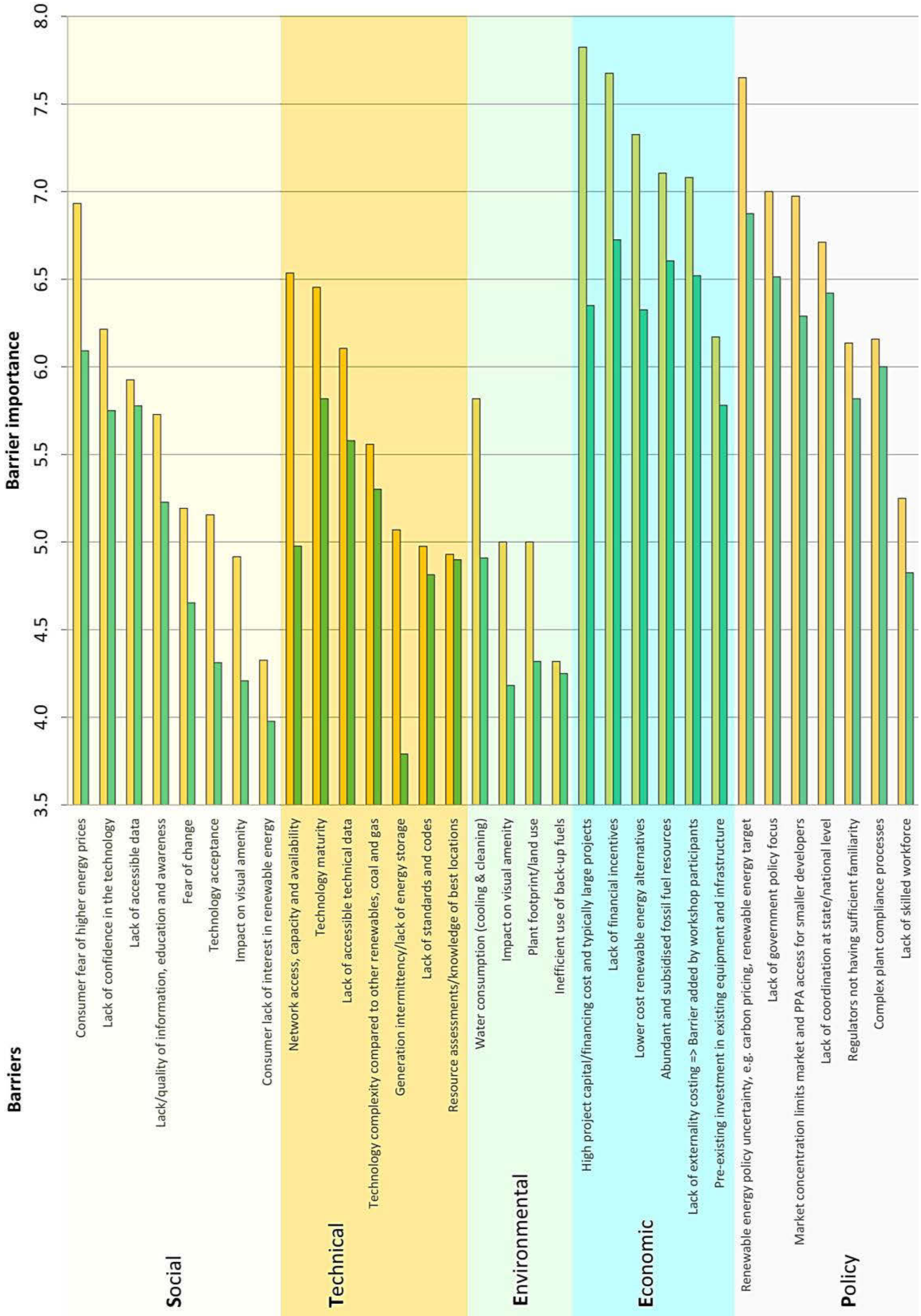

Figure 34: Barrier rating results for CSP-only (orange) and CSP hybrid plants (green)

4.5.2.1 CSP-only plants

The results for the individual barrier ratings are shown in Figure 34 and the category ratings with the participant group differences are shown in Figure 35.

The top five barriers identified for CSP-only plants in Australia are: 1) high project capital cost (average rating of 7.8 out of a maximum of 9), 2) lack of financial incentives (7.68), 3) renewable energy policy uncertainty (7.65), 4) lower cost renewable alternatives (7.3), and 5) abundant and subsidised fossil fuels (7.1) (see Figure 34). Pre-existing investment in equipment and infrastructure is considered the least important economic barrier (6.2). Four of the five top barriers are economic and Figure 35 shows that despite rating differences between the workshop groups all consider economics as the main barrier category. Based on the group ratings, owners/operators rated economic barriers as the most important (7.9) followed by technology providers (7.6) and government (7.5). Only researchers ranked the economics category significantly lower (6.5).

The second-most important category of barriers is policy with renewable energy policy uncertainty (7.68), lack of government policy focus (7.0) and market concentration (7.0) being the most significant. The technology providers (7.0), owner/operators (6.9) and government representatives (6.8) considered the policy category to be more significant than the group average (6.6). Lack of skilled workforce (5.3) was the least important policy barrier but was rated more significant by the owner/operator group (6.0).

On average technical barriers emerged as the third-most important barrier category with network access, capacity and availability (6.53) as well as technology maturity (6.45) considered to be the most important followed by lack of accessible technical data (6.1). Resource assessments and knowledge of the best locations was the least important technical barrier (4.9). Owners/operators rated the technical barrier category significantly more important (6.7) than the group average (5.7) with technology providers ranking it least significant (5.3).

Social barriers were rated the second-least important barrier category (5.5) with significant rating differences for the individual barriers. Fear of higher electricity prices was considered highly important (6.9), followed by lack of confidence in the technology (6.2) and lack of accessible data (5.9). Impact on visual amenity and consumer lack of interest in renewable energy were among the least important barriers with ratings of 4.9 and 4.3 respectively. Plant owners/operators and technology providers were the participant group that ranked the social barrier category highest (6.1) while the government group considered them significantly less important (5.1).

Not unexpectedly the environmental barriers were considered least important and all workshop groups rated them low (4.9 to 5.1). Water consumption was considered to be the most significant environmental barrier (5.8) and the inefficient use of back-up fuels least important (4.3).

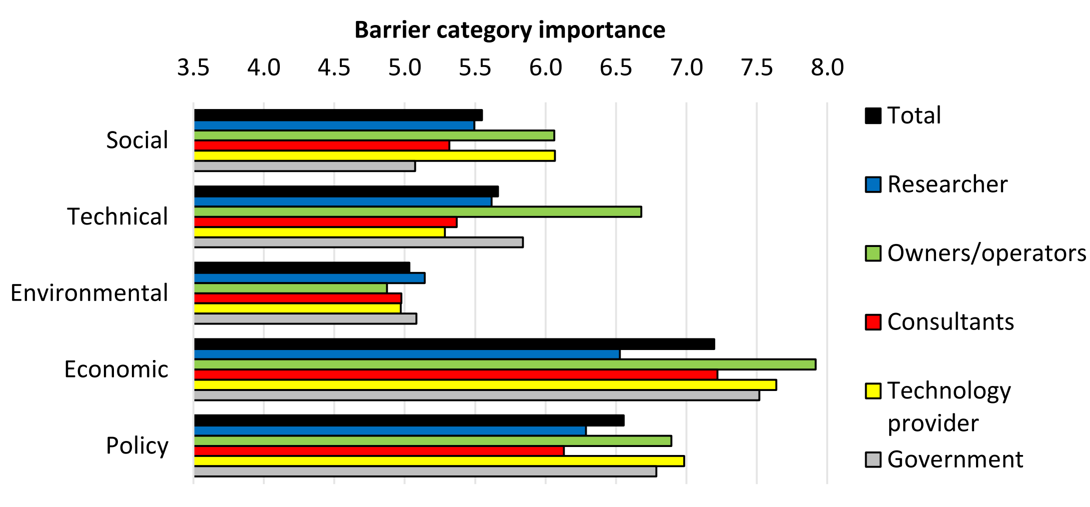

Figure 35: Barrier category ratings for CSP-only plants

4.5.2.2 CSP hybrid plants

The barrier category ranking for CSP hybrids in economic, policy, technical, social and environmental categories was similar to CSP-only plants and on average all barriers were considered less important for CSP hybrids (see Figure 34 and Figure 36). The top five barriers for CSP hybrids are: 1) policy uncertainty (6.9), 2) lack of financial incentives (6.7), 3) abundant and subsidised fossil fuels (6.6), 4) lack of government policy focus (6.5), and 5) high project capital cost (6.4). While four of the top five barriers are identical to CSP-only plants, their ratings were different and the barrier 'lack of government policy focus' (6.5) replaced the barrier 'lower cost renewable alternatives' (6.3). This demonstrates that the cost benefits CSP hybrids offer are recognised by a wider group of people.

Identical to CSP-only plants the economic barrier category was on average ranked most important (6.4) with the owner/operator group rating this category above average (7.1) and researchers below average (6.0). All groups considered the economic barriers less significant for CSP hybrids than for CSP-only plants.

Renewable energy policy uncertainty is considered the most important barrier (6.9) followed by lack of government policy focus (6.5) and lack of coordination at the state and federal levels (6.4). The lack of a skilled workforce was again considered the least significant policy barrier (4.8) and was again rated significantly higher by the owner/operator group (6.0). Of all groups the owners/operators considered the policy barrier category most important (6.7) with an almost identical rating from the government group (6.6). Only the consultants ranked it significantly lower (5.5).

The technical barriers were the third-most important category (5.0) and owners/operators rated it significantly more important (6.5) than the other groups (4.7 to 5.4). Technology maturity was the most significant technical barrier (5.8) followed by lack of accessible technical data (5.6), and technology complexity (5.3). Generation intermittency/lack of energy storage was not only rated the least important technical barrier but also the least important barrier of all (3.8).

Of all participants the owner/operator and technology provider groups considered the social barrier category significantly more significant (5.8) than others (4.6 to 4.7) which was similar to CSP-only plant rating. Also similar to the results for CSP-only plants, fear of higher electricity prices (6.1), lack of confidence in the technology (5.8), and lack of accessible data (5.8) ranked most important within the social barrier group.

The environmental barrier category was also least significant for CSP hybrid plants with the government group rating it more important (4.9) than the other groups (4.2 to 4.5). The most important barrier in this category was again water consumption (4.9) while the impact on visual amenity was considered the least important environmental barrier (4.2).

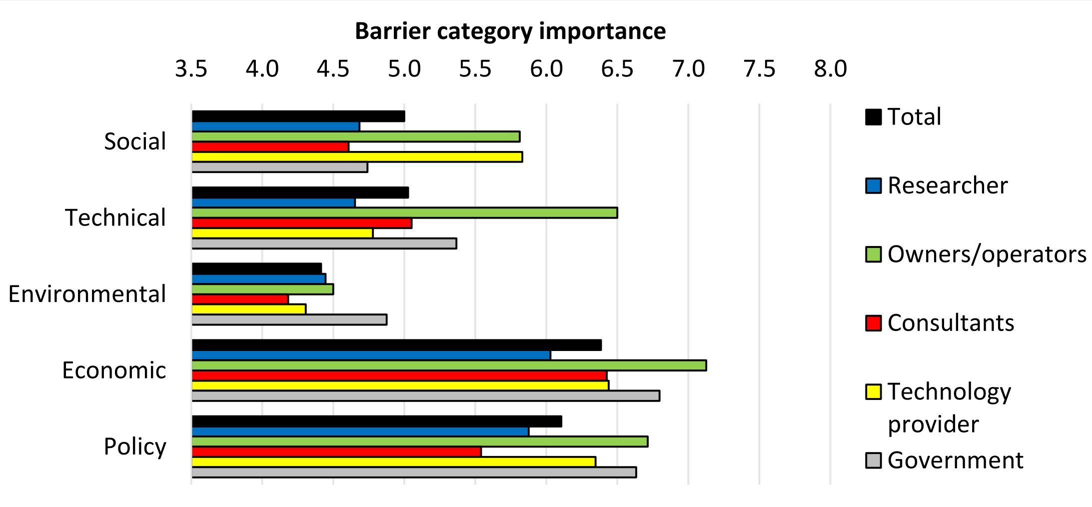

Figure 36: Barrier category ratings for CSP hybrid plants

4.5.2.3 CSP-only versus hybrid rating differences

On average all implementation barriers were considered less significant for CSP hybrids than for CSP-only plants but rating differences varied from marginal to significant. Table 2 shows these differences and due to the different backgrounds of the workshop participants/interviewees barrier rating differences can be observed. Technology providers

(ΔTP) for example ranked most barrier categories lower for hybrids than the other groups while owners/operators (ΔO) also ranked them lower but to a smaller extent.

Table 2: Ranking differences between CSP-only and hybrid plants showing total average and group averages for researcher (ΔR), owners/operators (ΔO), consultants (ΔC), technology provider (ΔTP) and government (ΔG)

Barrier category	Barrier	Δ Total	Δ Total	ΔR	ΔO	ΔC	ΔTP	ΔG
Social	Consumer fear of higher energy prices	-0.8	-12%	-1.2	-0.8	-1.2	-0.3	-0.2
	Lack of confidence in the technology	-0.5	-7%	-0.8	0	-0.3	-0.2	-1
	Lack of accessible data	-0.1	-2%	-0.1	0.3	-0.2	-0.7	0.3
	Lack/quality of information, education and awareness	-0.5	-9%	-0.3	-0.3	-1.1	0	-0.7
	Technology acceptance	-0.8	-16%	-1.5	-0.5	-0.6	-0.6	-0.5
	Fear of change	-0.5	-10%	-1.1	-0.3	-1	0.5	0
	Impact on visual amenity	-0.7	-14%	-1.3	-0.3	-0.5	-0.8	-0.3
	Consumer lack of interest in renewable energy	-0.3	-8%	-0.2	-0.3	-0.8	0	-0.3
	Group average	**-0.3**	**-10%**	**-0.5**	**-0.2**	**-0.4**	**-0.1**	**-0.2**
Technical	Network access, capacity and availability	-1.6	-24%	-2.1	-0.5	-1.8	-0.7	-2
	Technology maturity	-0.6	-10%	-1.2	0.3	-0.3	-0.9	-0.2
	Lack of accessible technical data	-0.5	-9%	-0.8	0	0.8	0	0
	Technology complexity compared to other renewables, coal and gas	-0.3	-5%	-0.8	1.3	0.1	-0.2	-0.7
	Generation intermittency/lack of energy storage	-1.3	-25%	-1.7	-2.8	-1.1	-1	-0.2
	Resource assessments/knowledge of best locations	-0.1	-2%	-0.2	0.3	0	-0.1	-0.5
	Lack of standards and codes	-0.1	-2%	0	0.3	0.1	-0.7	0.2
	Group average	**-0.2**	**-11%**	**-0.3**	**-0.3**	**-0.1**	**-0.3**	**-0.1**
Environmental	Water consumption (cooling & cleaning)	-0.9	-16%	-1.5	-0.3	-0.6	-1.1	-0.2
	Impact on visual amenity	-0.8	-16%	-1	-0.3	-0.7	-1.2	-0.3
	Plant footprint/land use	-0.7	-14%	-0.6	-0.5	-0.7	-0.7	-0.8
	Inefficient use of back-up fuels	-0.1	-2%	0.4	-0.5	-1.1	0.3	0.5
	Group average	**-0.6**	**-12%**	**-0.7**	**-0.4**	**-0.8**	**-0.7**	**-0.2**
Economic	High project capital/financing cost and typically large projects	-1.5	-19%	-1	-1.3	-1.7	-1.8	-1.6
	Lack of financial incentives	-1	-12%	-1	-1	-1	-0.9	-0.8
	Lower cost renewable energy alternatives	-1	-14%	-1	-1	-0.4	-1.1	-0.8
	Abundant and subsidised fossil fuel resources	-0.5	-7%	-0.1	-0.8	-0.2	-1.5	-0.3
	Lack of externality costing	-0.6	-8%	-0.4	-0.5	-1	-0.8	0
	Pre-existing investment in existing equipment and infrastructure	-0.4	-6%	0.5	-0.3	-0.5	-1.1	-0.8
	Group average	**-0.8**	**-11%**	**-0.5**	**-0.8**	**-0.8**	**-1.2**	**-0.7**
Policy	Renewable energy policy uncertainty, e.g. carbon pricing, renewable energy target	-0.8	-10%	-1.2	-1	-0.5	-0.8	-0.3
	Lack of government policy focus	-0.5	-7%	-0.5	0	-1	-0.4	0
	Market concentration limits market and PPA access for smaller developers	-0.7	-10%	-0.4	-0.5	-1.1	-0.8	-0.7
	Lack of coordination at state/national level	-0.3	-4%	-0.2	-0.5	-0.6	-0.3	0.2
	Regulators not having sufficient familiarity	-0.3	-5%	-0.4	0	0	-0.5	-0.7
	Complex plant compliance processes	-0.2	-3%	-0.2	0.8	-0.2	-0.7	0.2
	Lack of skilled workforce	-0.4	-8%	-0.1	0	-0.7	-1	0.2
	Group average	**-0.4**	**-7%**	**-0.4**	**-0.2**	**-0.6**	**-0.6**	**-0.2**

The highest barrier rating reductions between CSP hybrid and CSP-only plants can be observed for generation intermittency/lack of energy storage (25% less significant), network access, capacity and availability (24% less significant), and high project capital/financing costs (19% less significant) while the barriers with the smallest ranking differences were lack of codes/standards (1.5% less significant), inefficient use of back-up fuels (1.6% less significant), and resource assessment/knowledge of best sites (2.4% less significant).

The most significant ranking differences between the groups were for generation intermittency/lack of energy storage (ΔO 42% less significant compared to ΔG 4% less significant), technology complexity (ΔR 17% less significant compared to ΔO 19% more significant), and lack of accessible technical data (ΔR 12% less significant compared to ΔO 15% more significant). All three barriers are technical and the differences in the levels of technical expertise between researchers, government representatives and owners/operators are often large. Also owners/operators have to operate the plant over its lifetime while researchers are on the design side and therefore not exposed to financial and operational risks, which is a likely reason why they rated complexity lower. The barriers the participant groups ranked most closely are lack of financial incentives (ΔG 11% less significant compared to ΔR and ΔC 13% less significant), plant footprint/land use (ΔTP 12% less significant compared to ΔG 17% less significant), and lower cost renewable energy alternatives (ΔC 6% less significant compared to ΔTP 14% less significant). The responses for economic barriers show that economic barriers are uniformly considered important while the land use rating is likely to derive from the generally good land availability in Australia. However, this might be different in more densely populated regions, such as Europe.

4.5.3 Discussion

It is not unexpected that the economic and policy barriers were considered most important as they are key aspects in long-term decision-making. They are the most country-specific barriers because they are affected by federal/state legislation, electricity prices and other localised influences while the other categories are more universally applicable with overseas experience available on technical, social and environmental matters. A 2011 study on barriers to demand management (Dunstan, Ross & Ghiotto 2011) showed similar barrier ranking patterns with a lack of coordination at the state and federal levels ranked high, lack of information ranked average and consumer lack of interest in saving energy ranked low. This supports the trends identified in this study as barriers to energy efficiency and renewables are often similar.

The author believes that the reason the social barriers was considered most important by owners/operators and technology providers derive from their project development expertise and experience with community concerns. Similarly, the 'owners/operators' comparatively high technical barrier rating probably derives from knowing actual operational problems over a power station's lifetime. Some specific barriers are significantly lower for hybrid plants than CSP-only plants – for example generation intermittency/lack of energy storage, network access, capacity and availability, and high project capital/financing costs. Hybrid plants are likely to benefit most from improved energy dispatchability, lower cost and joint use of plant equipment. The minimal CSP hybrid to CSP-only rating differences for lack of codes/standards, inefficient use of back-up fuels, and resource assessment/knowledge of best sites are likely to be based on available codes/standards for all Rankine cycle systems, the small use of back-up fuels in CSP-only plants and maximum fuel efficiency expectations for hybrids considering rising fuel prices in Australia, as well as several available studies investigating suitable regions for CSP plants. While investment in pre-existing infrastructure was rated as important it is not in the top ten barriers. The reason for this is probably the significant average age of Australian power stations particularly coal-powered plants. Many units were built in the 1970s and '80s and are about to reach the end of their lifetimes. They will require replacement in the foreseeable future and therefore have a comparatively low asset value.

Due to the significantly lower economic and policy barriers for CSP hybrids they provide a good opportunity to break the detrimental CSP implementation cycle in Australia and elsewhere (see Figure 37) by reducing cost, thereby providing a higher incentive to build CSP systems and subsequently increase learning. The experiences gained with CSP hybrids are likely to raise confidence in the technology and investment in CSP and this will enable the construction of future CSP-only plants, thus breaking the vicious cycle.

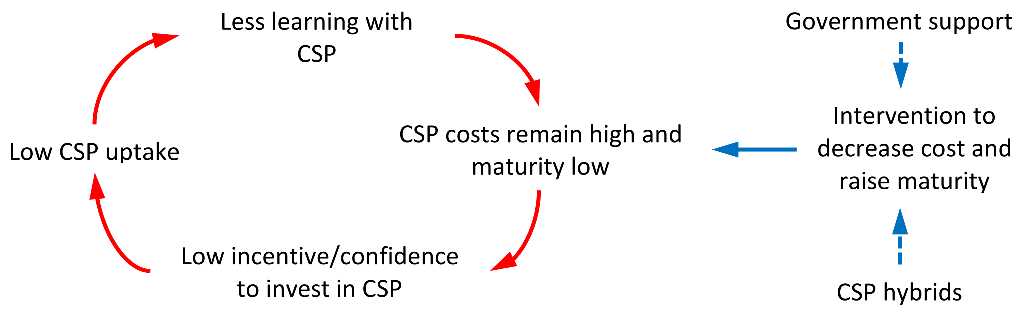

Figure 37: Detrimental CSP implementation cycle with intervention option. Adapted from Effendi and Courvisanos (2012)

While on average all hybrid barriers ranked lower than average, this is likely to vary depending on whether the fuel used in the hybrid plant is coal, biomass or waste. It is also likely to depend on the solar share, and in retrofit scenarios the host plant's age and remaining lifetime. Fully renewable CSP hybrids with biomass or geothermal components are likely to be more easily accepted by the community than hybrids using a waste or coal feedstock. In a CSP-EfW scenario community concern might arise over the use of recyclable materials for power generation and the resulting emissions. Both aspects can be addressed by pointing to the use of waste materials downstream of a recycling process (Gendebien et al. 2003), and by highlighting the advances in modern flue gas cleaning technologies (Psomopoulos, Bourka & Themelis 2009). Hybridisation with coal plants has to be considered carefully to avoid "greenwashing". Typically, coal fired power plants have a design lifetime of 40 years and units nearing the end of their lifetime should not be retrofitted with small commercial CSP plants to enable lifetime extensions. Two different examples exist in Australia at the Liddell and Kogan Creek coal fired power stations and these are discussed in Section 4.1. Despite the potential of CSP retrofits to significantly reduce economic barriers to implementation, such proposals have to be considered on a project by project basis to avoid negative environmental impacts and community opposition.

4.5.4 Conclusions

Currently, several key barriers limit the uptake of CSP in Australia and this research found that for both CSP-only and hybrid plants the economic and policy barriers are the most significant barriers, followed by technical, social and environmental barriers. Four of the top five barriers were identical for CSP-only and hybrid plants. They are: high project capital/financing cost, lack of financial incentives, policy uncertainty, and abundant and subsidised fossil fuels. However, there were significant rating differences in regards to generation intermittency/lack of energy storage, network access, capacity and availability, and high project capital/financing costs. For these barriers, the ratings for hybrids were significantly lower.

Based on the current policy and economic settings, CSP hybrids, both new plants and retrofits, seem a good option, not only for addressing technical and economic barriers, but also to help overcome significant policy, social and environmental barriers in Australia. The findings are supported by the fact that two hybrid projects are being operated/built in Australia while CSP-only plants have not progressed to the construction stage despite the selected offer of significant government support. The construction of CSP hybrids can provide technology providers, financiers, owners and operators with local experience and advance knowledge about the technologies. However, hybrid proposals, particularly retrofits to fossil fuel plants, have to be assessed on a project by project basis to ensure that they provide an overall environmental benefit or technology advancement and are not used to extend the operational lifetime of an aging generation asset.

4.6 Case studies

As mentioned in Section 3.2.4, two case studies at two sites in Australia were analysed to identify the technical, economic, environmental, and socio-economic benefits of CSP–EfB and CSP–EfW hybrid plants. Both case studies address the cost differences between CSP–EfB and CSP–EfW hybrids and CSP-only plants, the share of electricity generation from the individual energy sources and the plants' greenhouse gas mitigation potentials.

4.6.1 Swanbank, CSP-multiple feedstock hybrid

This case study is a 35.5 MWe CSP–EfB and CSP–EfW hybrid plant at the Swanbank landfill site in the Ipswich local government area in Queensland. The plant proposal is able to convert five different feedstocks very efficiently to electricity and to also potentially provide process heating and cooling. Section 4.6.1.1 provides a more detailed concept description. The Swanbank landfill is now owned and operated by Remondis Australia Pty. Ltd. The site was previously owned and operated by Thiess Services Pty. Ltd. and the case study was supported by this company financially and with detailed information about the site and feedstock quantities. Figure 38 shows the site with the proposed power station and existing infrastructure. The power plant proposal is a key element in a complementary visioning study on the economic and socio-ecological renewal of Swanbank (Baumann et al. 2012), which is endorsed by the local government (Ipswich City Council 2012).

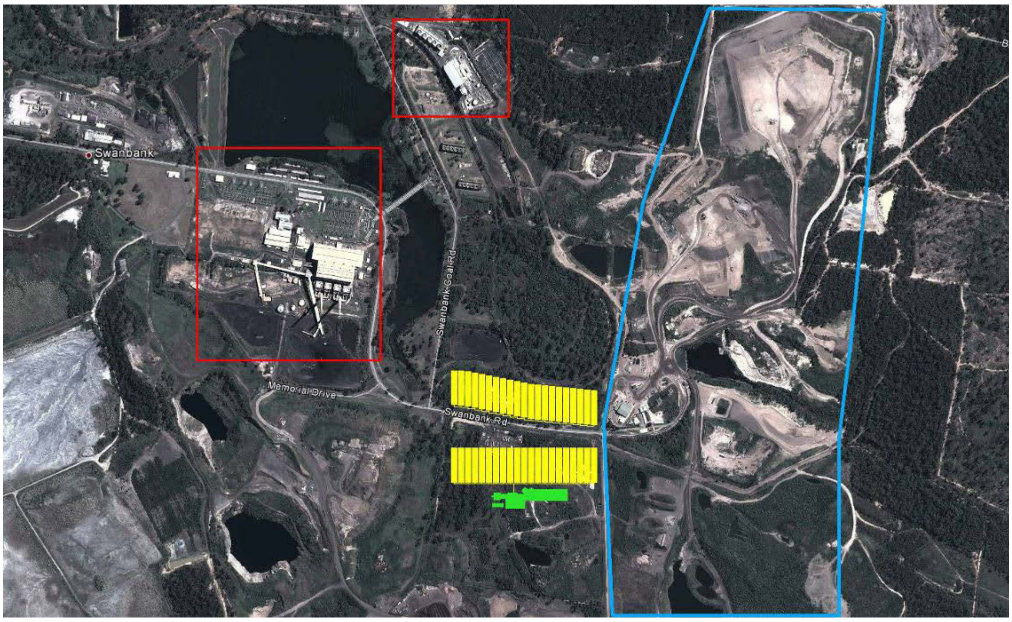

Figure 38: Swanbank site[14] with the proposed CSP–EfB and CSP–EfW hybrid plant (CSP = yellow and EfB/EfW = green), the existing coal fired Swanbank B power plant and the existing gas fired Swanbank E power plant (red squares), and landfill (blue polygon)

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[14] Map derived from Google Earth, version 7.1.2.2041

The architecture proposal for this power plant was produced by Elena Vanz, a PhD candidate in architecture and urban design at Melbourne School of Design at the University of Melbourne. She was given component dimensions and constraints in regards to component arrangements by the author and iteratively produced the plant layouts and renderings provided in the following conference publication. The author thanks her for her cooperation in this project and for her valuable insights into architecture and urban design.

The case study was presented at the SolarPACES 2012 conference[15] in Marrakech, Morocco, (Peterseim et al. 2012a) and published in the conference proceedings but unlike the other papers in this thesis, it was not peer-reviewed. In addition to the conference paper, Sections 4.6.1.2 to 4.6.1.5 provide further analyses of the environmental, economic and socio-economic benefits of this project as well as a synopsis of the plant's contribution to an economic and socio-ecological renewal at Swanbank.

4.6.1.1 SolarPACES 2012 conference paper

This conference paper outlines a highly efficient CSP-multiple feedstock hybrid plant concept for Swanbank capable of using of five energy sources in a single power plant. It also explains the technology selection process, discusses the power plant siting and provides an analysis of the proposed project's economic viability.

A more detailed process diagram than the one shown in Figure 3 in the conference paper is provided in the appendix.

[15] www.solarpaces2012.org, accessed 04 April 2014

CONCENTRATING SOLAR POWER / ENERGY FROM WASTE HYBRID PLANTS - CREATING SYNERGIES

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Abstract

Tightening environmental legislation and landfill restrictions require waste management companies to increase their environmental sustainability. Several options exist to meet these targets, such as increased reuse and recycling. Modern Energy from Waste (EfW) plants are another option when they do not compete with recycling efforts; refuse derived fuels (RDF) fulfill this criterion. This paper investigates the hybridisation of EfW with concentrating solar power (CSP) plants focussing on CSP technology selection, integration concepts, synergies and suitable locations. A case study in Queensland Australia is provided to place the concept in a real world context.

For CSP technologies a high direct normal irradiance (DNI) is essential, typically >2,000kWh/m^2/a for a stand-alone plant. However, for CSP/EfW hybrid plants lower DNI levels, >1,700kWh/m^2/a, are acceptable as hybrid plants use some plant components jointly and can therefore lower the specific capital investment. In addition the hybrid technology allows the CSP asset to move closer to load centers, reduce new network costs and ensure fuel availability. A DNI >1,700kWh/m^2/a is still significant but many countries, such as Australia, Greece, Turkey, Saudi Arabia and India, fit this criterion and are future growth markets for EfW and CSP systems.

Several CSP technologies are available for the hybridisation with EfW, such as parabolic trough, Fresnel, solar towers or dishes. Identifying the ideal technology is crucial and a variety of criteria have to be taken into consideration, such as land & water use, technology maturity and cost. CSP technologies in this paper were evaluated for feedwater heating, reheat steam and superheated steam meeting steam turbine requirements. Steam parameter considered range from 270-430°C.

CSP and EfW plants share similarities in terms of steam temperatures and capital investment. Steam temperatures of mature CSP technologies reach 440°C, which matches the steam temperatures of EfW plants well. Additionally, both technologies have high capital requirements and enabling them to share equipment, such as steam turbine, condenser, building infrastructure etc, will lead to specific cost reductions and make the hybrid plant concept more competitive.

Keywords: Energy from Waste, concentrating solar power, hybrid plants, Fresnel, multi-criteria decision making

1. Introduction

With electricity prices and demand typically being higher during the day in Australia [1] a CSP component attached to an EfW plant can provide additional capacity during these times while the EfW facility provides base-load power. This is particularly interesting for locations with high daytime ambient temperatures as they negatively affect the condenser performance which leads to a reduction in generation output. The hybrid system benefits from this configuration by providing more electricity to the grid during these economically attractive hours.

When hybridizing EfW plants with CSP a high DNI is essential. Typically, hybrid plants are viable in lower DNI areas than stand-alone CSP plants which enables them to move closer to load centers, avoid network costs and ensure fuel availability. The first Energy from Biomass (EfB)/CSP hybrid plant worldwide currently under construction in Spain proves these hybridization benefits, as it is located further north than any other CSP plant in Spain [2], [3].

For Australia, and other countries with a high DNI, the hybridisation of EfW with CSP technologies is promising to comply with landfill diversion targets and better align the capacity of power generation assets with demand profiles. EfW/CSP hybrid plants are likely to be niche solutions as several fuel resources have to be in one location and EfW plants typically have a smaller capacity, ≤35MWe.

2. CSP hybrid plant benefits

The main benefit of CSP hybrid over stand-alone CSP plants are immediate LCOE reductions of up to 28% [4]. Such reductions would reduce/eliminate the need for government incentives, allow plant suppliers and financiers to gain expertise, and are likely to accelerate the construction of CSP systems. The comparatively high LCOE of CSP is the key reason for its small contribution to global electricity supply.

Typically, renewable energy sources such as wind and solar suffer from poor capacity factors, 20-30% [5], compared to conventional fossil fuel plants, except for CSP with currently high cost thermal storage, AU$90/kWhth [6]. Hybrid plants have the ability to reliably provide electricity during the night, extended cloud coverage or DNI fluctuations, without thermal storage which is a significant benefit in terms of plant investment and complexity. Thermal storage systems could potentially be retrofitted at a later stage when costs reach the expected AU$22/kWhth by the end of this decade [6]. Additionally, CSP hybrid plants can follow daily electricity demand with the host plant operating constantly at design point and the CSP component satisfying the higher electricity demand during the day when electricity prices are economically more attractive.

Typically, CSP plants require a DNI >2,000kWh/m2/year to be commercially viable. Due to the joint use of equipment, such as steam turbine, condenser etc, CSP/EfB hybrid plants can be considered for DNI areas >1,700kWh/m2/year [7]. The first CSP/EfB hybrid plant near Barcelona verifies this assumption as it is the CSP installation furthest north in Spain. CSP/EfW hybrid plants could be build in even lower DNI areas as the low/negative fuel price for waste materials has a positive effect on the plants economic performance. DNI levels of >1,500kWh/m2/year are considered acceptable. Moving CSP out of arid/semi desert regions closer to agricultural/urban regions expands potential CSP sites and enables access of back-up fuel resources, e.g. agricultural and urban waste materials.

Currently, many power plant operators in Australia and elsewhere are not familiar with CSP systems and are therefore likely to favor technologies, renewable or fossil, they know over CSP when deciding on new generation assets. CSP hybrid plants would allow them to use current staff while simultaneously up-skilling them to confidentially operate initially smaller but subsequently larger and larger CSP installations.

With CSP/EfW & EfB hybrid plants unlikely to exceed plant capacities of 60MWe such systems can be considered distributed generators that could be placed close to demand centers. This not only reduces transmission losses but also offers the chance to avoid/defer investment in transmission and distribution infrastructure, which are main drivers of current electricity prices rises. In Australia distribution infrastructure is expected to be responsible for 42% of the total electricity price increase from 2011-12 to 2013-14 and transmission 8% [8]. Moving CSP closer to load centers also increases chances for highly efficient combined heat and power applications.

3. Energy from Waste/biomass hybrid concepts

Principally, the CSP component of a hybrid plant can provide steam at different qualities. Low-temperature options include feedwater heating, mid-range temperature options include saturated steam into the high pressure boiler drum or steam into the cold reheat line, and the high-temperature option is superheated steam to the joint steam turbine, see Figure 1.

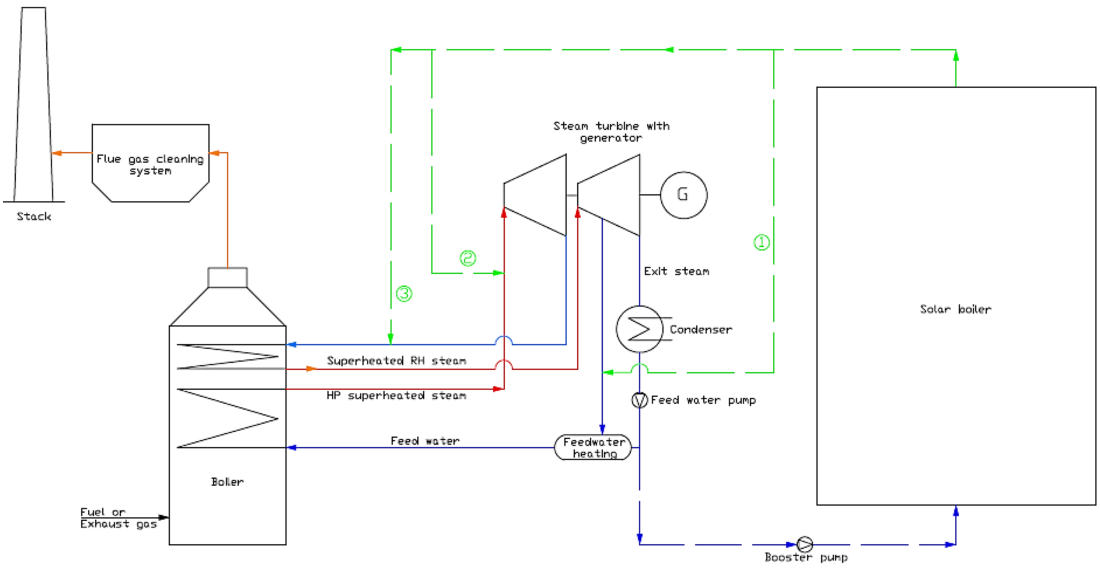

Figure 1: CSP integration options into an EfW plant; 1 = feedwater heating, 2 = cold reheat line, 3 = high pressure/temperature turbine steam

First concepts to pair biomass and waste materials with CSP were investigated at a high level in the mid 1980's with paraboloidal dish systems [9] but no plants were built. It took another 25 years before construction of the first commercial CSP/EfB hybrid plant, 25MWe [3], commenced ca. 150km west of Barcelona, Spain [2]. To minimise risk the plant uses the mature parabolic trough technology with thermal oil [3]. The disadvantage of having the biomass system in the thermal oil loop (see Figure 2) is the lower steam temperature of

375°C compared to 450°C, which is technically possible with forestry and agricultural waste materials. Other parabolic trough concepts integrate the biomass system into the secondary water-steam cycle to increase plant efficiency (see Figure 2), e.g. 107MWe hybrid plant proposal at San Joaquin, US [10].

Currently, no CSP/EfW hybrid plants are under construction anywhere in the world but EfW steam temperatures, typically 380-440°C [11], match well with current CSP technologies, such as parabolic trough, Fresnel or solar tower. Some studies investigate the integration of Fresnel [11], [12] and parabolic trough systems in EfW plant [11], [13]. Concepts discussed include the use of CSP for air and feedwater heating [11] as well as the generation of identical steam parameters as the host plant using Fresnel [12] and parabolic trough systems [11], [14]. External EfW steam superheating using Fresnel is being investigated [14] but seems unlikely to be a reliable option for high-temperature steam supply. All of the concepts consider CSP steam temperatures <430°C.

The hybridisation of EfW with paraboloidal dish systems was briefly discussed in the past [9] while solar towers are currently being investigated for construction and demolition timber as well as RDF [15].

Some EfW plants are hybridized with combined cycle gas turbine (CCGT) plants. The EfW plants Moerdijk in the Netherlands [16], Mainz in Germany [17] and Bilbao in Spain [18] provide steam to the heat recovery steam generators of adjacent CCGT plants for further superheating. An EfW plant in Måbjerg, Denmark has taken a different approach using natural gas to further superheat the steam [19]. All these plants raise the final steam temperature from <430°C to >520°C, therewith increasing the overall conversion efficiency.

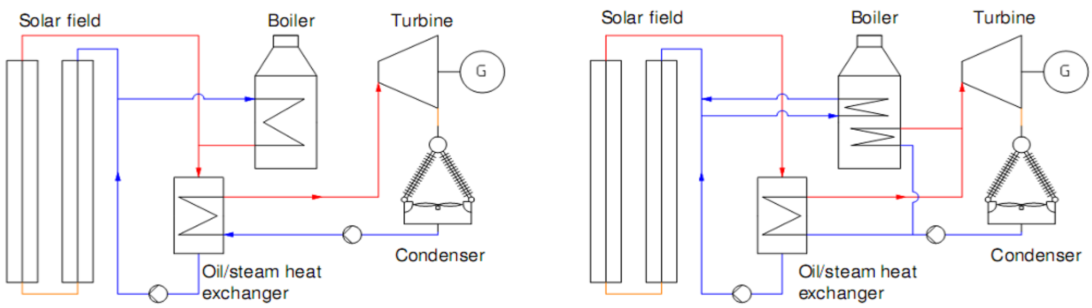

Figure 2: Simplified hybrid concept for the Termosolar project, Spain (left) and San Joaquin proposal, US (right)

4. Swanbank case study, Queensland, Australia

The Swanbank landfill at Ipswich, Queensland is owned and operated by Thiess Services Pty Ltd. The site is ideal for a new power station as it is an industrial zoned area with a long tradition in power generation, recently decommissioned 480MWe coal fired and one operating 385MWe CCGT power station.

With Ipswich being one of the fastest growing communities in Australia the proposed power plant could provide new local industries and residential areas in its vicinity with renewable and low-carbon intensity electricity, heating and cooling while creating long-term high value employment.

The landfill has the capability to ensure long term supply of wood waste, refuse derived fuel (RDF), landfill- and biogas for a 35.5MWe net power plant, EfW contribution 30.7MWe and

CSP contribution 4.8MWe. Fuel availability is a significant benefit as the reliable supply from local sources is the main criteria for an EfW and EfB power station. Using the aforementioned fuels would defer ca. 150,000t/a waste from landfill without sacrificing recycling efforts as only solid materials downstream a recycling process are used.

The proposed plant is modeled with Thermoflex Version 22.0.1, can generate up to 252,800MWh per year, see Table 1, and follow daily demand with its main fuels. It also has the potential to provide extra steam from the solar field during the day to increase the plant output when electricity demand/prices are high.

Peak net annual power output	252,800MWh
Net power output wood waste and RDF component	245,600MWh
Peak net power output of the CSP component	7,200MWh

Table 1: Maximum annual power plant electricity output

4.1. Plant concept

The Swanbank hybrid is designed to maximize plant efficiency. Due to a novel plant hybrid concept the power station achieves an electric net efficiency of 33.6% which is significantly higher than the 30% of other modern EfW plants, such as the significantly larger, 66MWe, EfW plant in Amsterdam, Netherlands [20].

The simplified technical concept of the Swanbank CSP/EfW hybrid plant is outlined in Figure 3. Upon waste arrival the fuel is sorted in the material recovery facility. Recyclable materials and waste destined for landfill leave the facility while the organic rich fraction, wood waste and RDF are suitable power plant feedstocks. Two third of the solid material used in the power station is wood waste, 12.5t/h, and the remaining third RDF, 6.25t/h. Up to 2,600m^3/h of bio- and landfill gas are required during peak capacity operation.

Wood waste and RDF are supplied to the boiler which is generating steam at 430°C and 90bar. The steam temperature is chosen to minimise high temperature corrosion issues inside the main boiler. The solar field is generating identical steam parameters as the main boiler and both steam flows are combined before entering an external superheater. The organic rich fraction of the waste material is digested in Thiess Services proprietary biocell technology [21] and the biogas, in combination with available landfill gas, is fired into an external superheater to further raise the steam temperature from 430°C to 530°C. External superheating of EfW steam has been realised at the EfW plant in Måbjerg, Denmark using natural gas [19].

The combined high pressure/temperature steam flow, up to 117t/h, enters one steam turbine. The turbine exit steam is condensed, using a water cooled condenser, and pumped back into the solid fuel boiler and solar field, thus closing the thermodynamic cycle. Flue gases are cleaned according to Australian emission limits using scrubbing and baghouse filter systems.

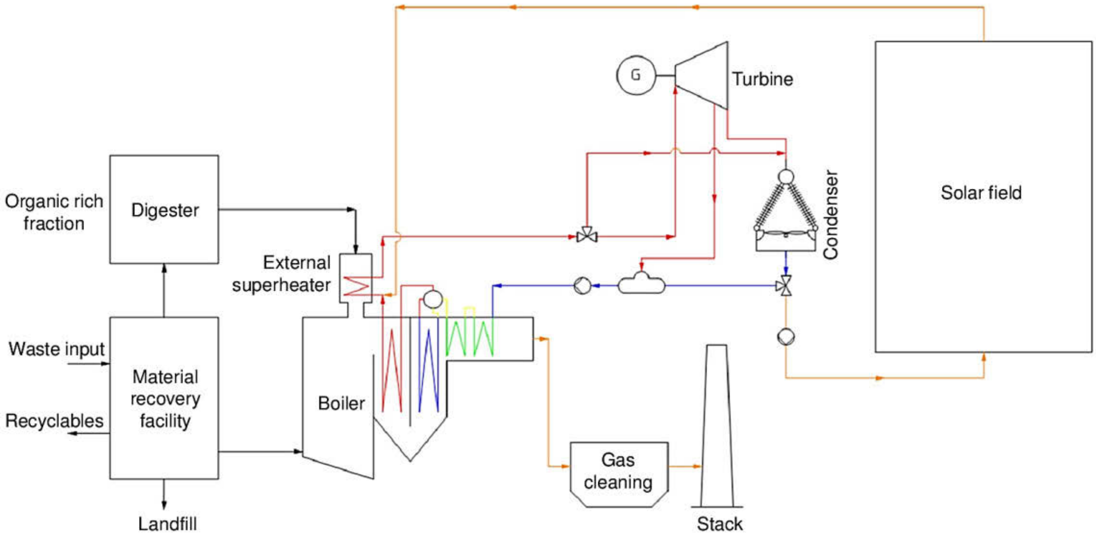

Figure 3: Simplified concept of a CSP / solid fuel hybrid plant with external superheating

4.2. Technology selection

Several CSP technologies are available for hybridisation with an EfW facility and in this assessment we considered the following:

- Parabolic trough; thermal oil (TO), direct steam generation (DSG) and molten salt (MS)
- Solar tower; molten salt (MS), direct steam generation (DSG) and air (A)
- Fresnel; saturated (Sat. St.) and superheated (Sup. St.) steam
- Paraboloidal dish; direct steam generation (DSG).

In July 2011 we organised a workshop at the University of Technology Sydney with 49 industry professionals with different expertise in the energy business (plant operators, technology provider, financiers and researcher) to identify the best CSP technologies to integrate into, amongst other, wood waste and RDF plants. The following steam temperatures scenarios were investigated:

- Live steam at 430°C to steam turbine,
- Steam at 300°C into the cold reheat line, and
- Steam at 270°C for feedwater heating.

To identify the best CSP technology for the Swanbank project we used the Analytical Hierarchy Process (AHP) as it allows the decomposition of a complex problem into several sub-problems, such as land use with levelised cost of electricity (LCOE), and provides a comprehensive and rational decision making framework [22]. The method is widely used in the research and industry world, including assessments comparing fossil fuels with renewable sources [23] and different CSP standalone technologies with each other [24].

The problem decomposition takes place by identifying criteria (main- and sub-criteria) relevant to the problem and organizing them in different levels of hierarchy. The AHP can use precise criteria data (quantitative information) as well as the personal judgments (qualitative information). Subsequently, quantitative and qualitative information can be merged to calculate the total score for each option. Four main criteria groups (feasibility, risk reduction, environmental impact reduction and LCOE) with several sub-criteria, such as land and cleaning water use, site gradient tolerance, technology maturity, peak efficiency, complexity, were chosen to cover the relevant aspects of the Swanbank multi-criteria decision problem.

We identified quantitative data for all criteria from literature as well as own calculations/modeling. These quantitative data were merged with qualitative data derived from the participant's individual rating of the main/sub-criteria importance. CSP technologies with the highest total score are the preferred options. To accommodate uncertainties in the input data a ±10% sensitivity is applied to all results. As seen in Figure 4 not all CSP technologies can achieve the steam temperatures required for the different scenarios. CSP technologies unable to produce the desired steam temperature were excluded from the assessment.

For the integration of a CSP component into the high pressure/temperature steam cycle of a wood waste/RDF host plant the Fresnel technology with superheated steam scores best, see Figure 4, and is therefore the chosen technology for the Swanbank project. The reasons for the good score of Fresnel systems providing superheated steam include the low cleaning water requirements through robotic cleaning of the flat mirror panels, and the compact solar field minimizing land use.

Fresnel (superheated steam) and parabolic troughs (thermal oil) systems would be the preferred options for cold reheat steam, while parabolic troughs (thermal oil) score best for feedwater heating followed by Fresnel (saturated steam). However, these options are not considered in the Swanbank case study as they would reduce the CSP contribution to the overall plant output compared to high pressure/temperature turbine steam.

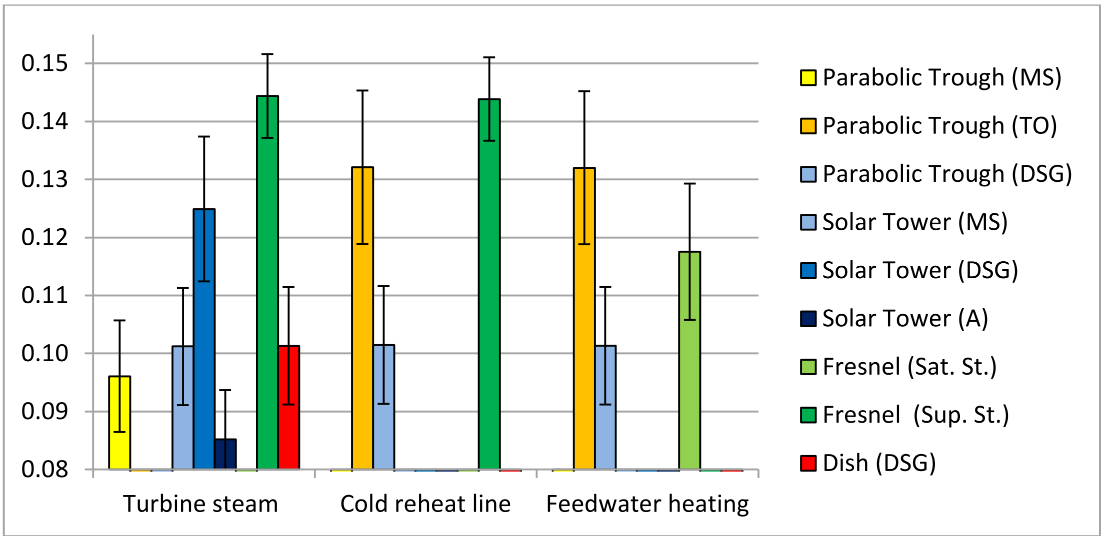

Figure 4: CSP technology selection for Swanbank hybrid plant

4.3. Plant siting and layout

As mentioned earlier CSP stand-alone plants typically require a DNI of >2,000kWh/m^2/a. However, through the joint use of equipment the site with a DNI of only 1,890kWh/m^2/a is still suitable for a CSP hybrid plant.

Space is constrained at Swanbank with the only possible site for a power plant south-west of the currently active landfill. A benefit of the location is the proximity to the current and new landfill which reduces material transport. The selected site is not level yet but earthworks to do this are not significant.

With the CSP component requiring the largest area its footprint is the limiting factor for the energy contribution. By arranging the EfW facility in the south, stretching from east to west, the area north of it is maximised for the CSP field, see Figure 5. To accommodate two Fresnel fields they have to be located north and south of the access road to the landfill. The fuel-exhaust gas flow of the power station is east to west, starting with the fuel processing facility, fuel storage, boiler, gas cleaning and stack. The steam turbine, auxiliary, workshop and cooling tower buildings are located south of the plant.

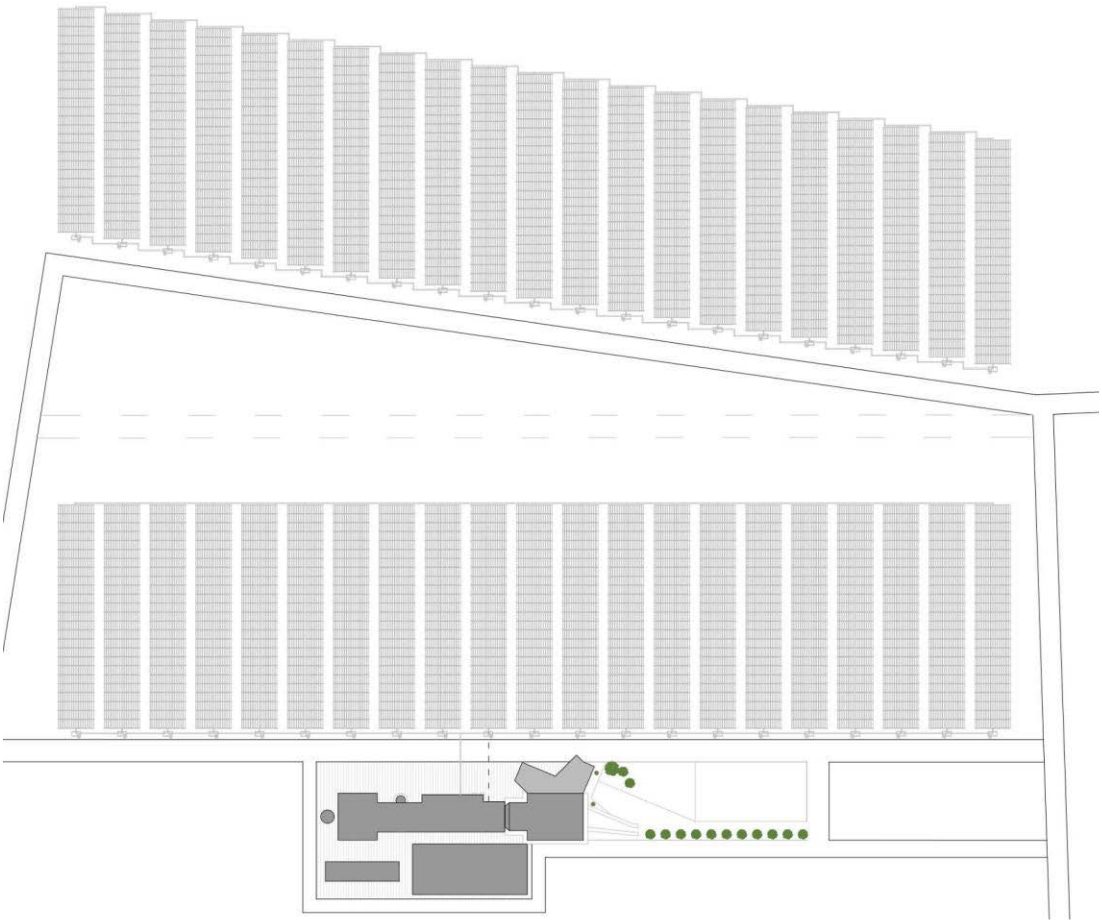

Figure 5: Plant layout of the Swanbank hybrid power station

Figure 6: Artist impressions of the proposed Swanbank hybrid power station[16]

4.4. Economic analysis

The economic modeling is carried out with Thermoflex Version 22.0.1 and based on a plant life of 25 years. It includes capital as well as operational expenditures, e.g. personnel, fuel, water and residue disposal costs, as well as escalation rates for inflation, fuel, electricity, water and CO_2 prices. All assumptions are based on the plant commencing operation in 2017.

In the base case scenario the solid fuels are considered to have zero fuel cost while the assumed landfill and biogas price is AU$5/GJ. Depending on the future market developments for green waste and construction and demolition timber modeling was carried out for AU$-10, AU$10 and AU$20 per ton of solid fuel, Table 2.

The base case wholesale electricity price scenario assumes $45/MWh. With electricity prices currently increasing scenarios were modeled for electricity prices ranging from $30-$70/MWh, see Table 2.

The base case scenario is a renewable energy certificate (REC) price of $35/MWh. Due to fluctuations in the REC market scenarios were modeled for REC prices ranging from $30-$50/MWh, see Table 2.

The total investment for the power station is expected to be around AU$150-160m or 4.2-4.5m/MWe net. This price includes the fuel processing and storage facilities as well as grid connection. Considering the additional investment for the solar component the investment is in line with other EfW & EfB installations.

The levelised cost of electricity of the new installation is expected to be between AU$80-120/MWh, see Table 2. The final investment strongly depends on detailed negotiations with EPC plant contractors, expected CSP cost reductions in the next 3-4 years as well as fuel, carbon and renewable energy certificate pricing.

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[16] Architecture proposal by Elena Vanz, PhD candidate in architecture and urban design at Melbourne School of Design, University of Melbourne

The modeling considered electricity generation only but the supply of process heat/cold to adjacent industries would strengthen the economic case and reduce the payback times of the different scenarios by up to 25%.

Except for scenario 1, see Table 2, the power station has a payback within its operational life but the scenario 2 and the base case scenario are not particularly attractive to institutional investors without other financial incentives. It is obvious that the electricity price agreed in a power purchase agreement has a significant impact on the plant's commercial viability. The fuel prices are relevant too but to a significantly lesser extent.

Scenarios	Solid fuel price in $/t	Electricity in $/MWh[17]	Payback in years
Scenario 1	20.00	60.00	>25.0
Scenario 2	10.00	100.00	14.5
Base scenario	0.00	80.00	15.1
Scenario 3	0.00	100.00	13.3
Scenario 4	0.00	120.00	10.6
Scenario 5	-10.00	100.00	12.3
Scenario 6	-10.00	120.00	9.9

Table 2: Economic viability of the hybrid power plant for different fuel and electricity price scenarios

5. Conclusion

The hybridization of CSP with non-conventional fuels is likely to be a niche market compared to natural gas or coal hybrid systems but allows, subject to waste material composition, renewable base-load power generation. Only waste materials downstream a recycling process should be considered for such plant concepts.

All the individual components required for the Swanbank CSP/EfW hybrid project are proven with reference plants in operation using wood waste and RDF fired boilers, Fresnel systems, external steam superheating, and bio- / landfill gas combustion. The combination of the individual components is new but manageable with experienced project partners and modern power plant engineering tools.

The Swanbank site is ideal for such a concept as the landfill ensures fuel supply over the operational lifetime of the plant, the CSP system provides additional power during high electricity demand/price times and staff from the recently decommissioned coal fired power station could be recruited to operate the new facility. Due to the joint use of plant equipment the LCOE are competitive compared to other forms of renewable energy and the concept demonstration could trigger the development of similar projects in Australia and overseas.

[17] Includes wholesale and renewable energy certificate prices

Acknowledgements

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4.6.1.2 Environmental analysis

The Swanbank hybrid plant proposal is designed to use predominantly renewable energy sources, such as wood waste, landfill gas, biogas and CSP, and the only feedstock with a fossil content is RDF. The renewable content of RDF ranges from 40–60% (Arias-Garcia, Gleeson & Ltd 2009; BGS e.V. 2011) and renewbale materials include wood, cardboard and paper waste. The following assessment is based on fossil fuel CO_2 emissions from the RDF combustion and preparation of 652 kg CO_2/t RDF (Arias-Garcia, Gleeson & Ltd 2009) which, when combined with the RDF consumption of 50,000 t/year and electricity generation of 252,800 MWh, leads to a carbon intensity for the Swanbank proposal of 129 kg CO_2/MWh. This is significantly lower than the 2010 average carbon intensity of Australia's electricity generation of 841 kg CO_2/MWh (International Energy Agency 2012a) and the expected average carbon intensity from 2017–42 of around 673 kg CO_2/MWh[18] (ROAM Consulting Pty Ltd 2011). Comparing the carbon intensity at Swanbank with the ROAM Consulting (2011) average carbon intensity leads to a CO_2 abatement potential of 3.4 million tonnes over the plant's 25-year operational life. It is worth mentioning that the 673 kg CO_2/MWh seems high but according to the aforementioned report the emissions intensity of grid-sourced electricity is expected to stay above 500 kg CO_2/MWh until around 2038.

Energy recovery from wood waste, the biogenic RDF portion and the use of biogas from the organic rich fraction can reduce potent future landfill gas emissions by increasing the current landfill gas capture rates from 50–65% to above 98%[19] when the organic materials are processed in anaerobic digesters. The total organic carbon in the post-combustion products, ash and slag, would be below 3% before landfill, which meets a requirement introduced in Germany that contributed to only 1% of municipal waste going to landfill (European Environmental Agency 2009). When considering avoided landfill gas emissions the aforementioned carbon intensity of 129 kg CO_2/MWh would be lower or even negative, which is in line with other EfB/EfW life cycle assessments (Sathaye et al. 2011).

Considering that annually 150,000 t of predominantly renewable energy feedstock is currently being landfilled at Swanbank, and in view of the availability of other renewable sources such as landfill gas and solar irradiance, the use of these resources represents a cost effective means of diverting waste from landfill and generating renewable electricity without sacrificing recycling efforts.

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[18] 2017-2042 carbon intensity calculated with data from the ROAM Consulting (2011) report

[19] Personal communication with Frank Klostermann, formerly Manager Engineering and Strategy at Thiess Services Pty. Ltd., during the feasibility study.

4.6.1.3 Hybrid versus CSP-only cost comparison

The DNI at Swanbank is 1,890 kWh/m^2/a (Bureau of Meteorology 2012) which is sufficiently high enough to operate a CSP-hybrid and in fact better than the 1,800 kWh/m^2/a at the site of the 22.5 MWe Termosolar Borges CSP–EfB hybrid plant in Spain (Morell 2012). One of the main benefits of a CSP hybrid at this site is the cost reduction through the joint use of plant infrastructure such as the steam turbine and condenser. The specific cost for the 4.8 MWe CSP component at Swanbank, including its share of the use of the steam turbine, cooling system, buildings, roads, control system and other infrastructure, is AU$ 5m/MWe (net). A 4.8 MWe CSP-only plant on the same site would have a specific cost of AU$ 8.3m/MWe (net) and therefore the CSP hybridisation at Swanbank leads to a 40% cost reduction. This is significant and mainly a result of the comparatively small CSP system (4.8 MWe net) benefiting from the much larger EfB/EfW component (30.7 MWe net). This, for example, leads to a steam turbine cost, including installation, of AU$ 3.4m in the 4.8 MWe hybrid scenario compared to AU$ 7.4m for the CSP-only scenario. Also the Fresnel field itself would be larger and more capital intensive in a CSP-only scenario due to the lower net cycle efficiency of 29.1% (with steam parameters of 500°C and 90 bar) compared to the 33.6% Swanbank hybrid scenario. The cycle efficiency difference results from the economies of-scale that the larger power plant equipment offers and the slightly higher steam temperature due to external steam superheating to 530°C at 90 bar.

The significant cost difference between the CSP hybrid and CSP-only scenarios at Swanbank allows the construction of a CSP plant which would otherwise not be economically viable. This supports the assumption that CSP hybrid plants can fast track CSP implementation in Australia and it can enable technology suppliers, operators and financiers to advance their local understanding of CSP, gain practical experience, and progress the knowledge of technology with minimal dependence on government incentives.

4.6.1.4 Socio-economic benefits

The economic uncertainties currently affecting the world make the social acceptance of any energy project very much related to the potential net impact that such an activity will have on stimulating the economy as well as creating new employment opportunities. In fact, the latter is one of the reasons frequently given for encouraging renewable energy deployment. Several studies have analysed the socio-economic drivers and benefits of renewable energy projects (Caldés et al. 2009; Deloitte 2011; Domac, Richards & Risovic 2005; Wei, Patadia & Kammen 2010) and comparing the employment of 0.11 job years/GWh for coal and gas fired generation with 0.21 job years/GWh for bioenergy and 0.23 job years/GWh for CSP

(Wei, Patadia & Kammen 2010) shows a significantly higher job creation from the renewable alternatives. This is one of the reasons why the Swanbank proposal has the potential to generate a very positive socio-economic net impact for the Ipswich local government area in regards to employment generation as well as economic development.

To assess the economic and employment stimuli of a project one must consider not only its effects on sectors directly affected by a project, but also its impact on sectors that supply goods and services to the directly affected sectors. One must also consider the induced effects – that is, the impact on the economy in general due to the economic activity and spending of direct and indirect employees. One of the most widely used methodologies to quantify the total direct and indirect effects of any given project on the economy is the input-output methodology (Ten Raa 2006). This methodology is a tool to systematically gather information about the productive relations between the different sectors in any given country or regional economy. Besides estimating the associated direct and indirect effects on the economy and on employment creation, input-output models are used to estimate the multiplier effect that a certain investment generates in the economy.

Operating the proposed Swanbank power station would require about 30 staff, an estimate which is in line with another EfB employment study by Thornley et al. (2008), and would additionally secure current employment on the landfill through business diversification, for example for a material recovery facility in addition to the landfill operation. Operator positions could be filled with personnel from the recently decommissioned Swanbank B coal fired power station. This would not only train these personnel to operate a renewable energy asset and future proof their careers, but it would also de-risk the initial phase of plant operation due to their relevant expertise with thermal power plants. Based on the literature quantifying the employment from EfB power plants (Thornley, Rogers & Huang 2008) the indirect and induced employment an EfB plant creates can be 10 times higher than its direct employment. This includes employment in feedstock growth, harvesting, transport, and equipment supply and maintenance. However, these numbers cannot be transferred entirely to the Swanbank proposal as the biomass and waste materials are already going to landfill through existing transport infrastructure. Also, feedstock cultivation will not be required. Considering these factors the additional employment could reach a multiplier factor of five through the additional operation of a material recovery facility and limited transport and supply change increases caused by the need for additional residue and recycling material transport. In a growing council area where many people commute elsewhere for work, this presents an opportunity worth pursuing.

Based on the more conservative investment estimate of AU$ 160m for the Swanbank power plant, and assuming an Australian-based engineering procurement and construction (EPC) company, 58% or AU$ 93m of the investment is expected to remain in the Australian economy (see Table 3). The network connection is not included in this cost but could be significant depending on the accessibility of existing infrastructure at the adjacent Swanbank E combined cycle power plant (see Figure 38 on page 160). Of this AU$ 93m, a large percentage would remain in the Queensland and Ipswich economies in investments related mainly to plant construction, equipment installation and some component manufacturing. Only 42% or AU$ 67m of the plant investment would flow overseas for the manufacture of major plant items, such as boiler, steam turbine and condenser systems.

Table 3: Swanbank power plant cost breakdown and investment distribution

Cost breakdown	Investment, AU$m	Australian content, AU$m (%)	Overseas content, AU$m (%)
Turbo generator set	25	5 (20%)	20 (80%)
Boiler system	36	18 (50%)	18 (50%)
Flue gas cleaning	26	16 (60%)	10 (40%)
Solar Field	15	10 (65%)	5 (35%)
Condenser/cooling system	5	3 (50%)	3 (50%)
Balance of Plant	10	7 (70%)	3 (30%)
Fuel processing facility	15	12 (80%)	3 (20%)
Buildings and roads	20	19 (95%)	1 (5%)
Electricals & controls	8	4 (50%)	4 (50%)
Total	160	93 (58%)	67 (42%)

To determine the multiplier effect of the Swanbank hybrid plant the individual contributions from the main energy sources have to be considered. For biomass electricity generation a multiplier effect of 1.32 has been published (Gan & Smith 2007), which excludes feedstock procurement, as in this case study the materials are already transported to the current landfill. For CSP a multiplier effect of 2.3 was used in another study (Caldés et al. 2009). Combining these two values proportionally to the 35.5 MWe plant capacity, 30.7 MWe from EfB and EfW and 4.8 MWe from CSP, results in a combined multiplier effect for Swanbank of 1.45. Based on this multiplier the direct plant investment would lead to an overall financial stimulus to the Australian economy of AU$ 135m.

4.6.1.5 Economic and socio-ecological renewal at Swanbank

In addition to the techno-economic analysis of the Swanbank power plant proposal the author was part of a research team which prepared a report on a vision for the economic and socio-ecological renewal at Swanbank (Baumann et al. 2012).

Ipswich is one of the fastest growing regions in Australia with substantial new commercial and residential developments around the current industrial site. The power plant proposal will help integrate the current industrial area into this new environment by creating employment opportunities, providing low-carbon intensity energy, and enhancing waste management. Figure 39 shows how the proposed power station can be developed in the area to contribute to the transformation of the site into an eco-industry park with an integrated waste and energy management system.

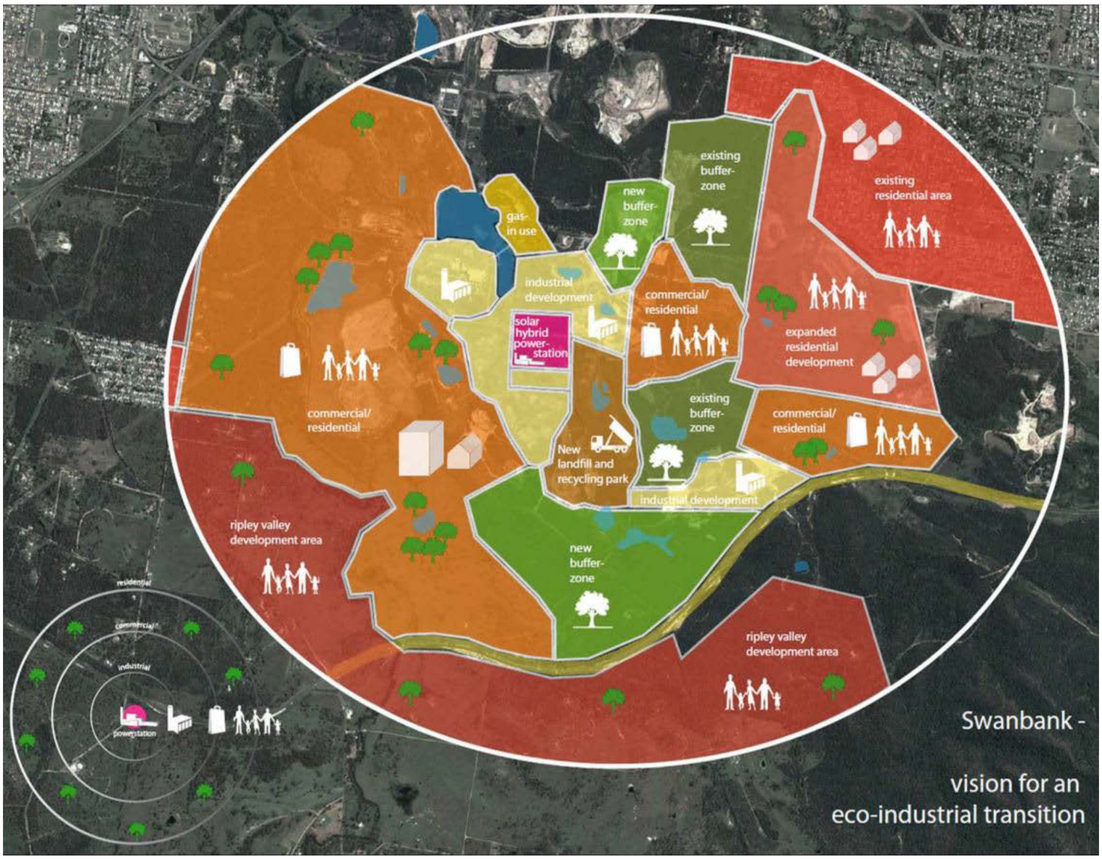

Figure 39: Vision for an eco-industrial transition – map and concept, Baumann et al. (2012)

Adjacent to the proposed power station site sufficient land is available to co-locate new industries and provide them with electricity and potentially significant quantities of process heat and/or energy for cooling. In addition to industry consumers, which typically require high value process steam, commercial and residential developments could be supplied with electricity as well as lower grade heat and/or cooling through a district heating/cooling network. A particular benefit would be the low and stable cost of energy given that the energy sources, biomass and waste, are already available and largely independent of world oil and gas prices, as is CSP. This has the potential to be a major driver to attract further commercial and industrial developments, create additional employment and help diversify the business profile of the area. A diverse local economy would also lead to residents spending and re-spending more money in Ipswich rather than in other council areas as they would have access to various services in their local area. This in turn would strengthen the local economy, finance additional investments and ultimately create further business opportunities, employment and tax revenue.

The waste streams arising from existing and new residential, commercial and potentially industrial developments could be sent to the landfill for recycling and energy recovery. With this circular economy concept the different local stakeholders would complement and mutually benefit each other, for example by ensuring stable waste disposal costs and feedstock for stable energy costs. In particular, energy intensive industries, such as food processing, would benefit from stable energy prices as these industries have experienced electricity price increases and now expect significant rises in natural gas pricing.

To separate the industrial facilities from the residential developments buffer zones as well as commercial areas would be required, with the proposed power station located in the centre of the industrial area (see Figure 39). In close proximity to existing and potentially new industrial facilities dense commercial developments could emerge, thinning out towards existing and new residential developments. Buffer zones, including areas created by the conversion of the old landfill site into a green area, could be expected to include parks for recreational purposes.

Currently, most people in the Ipswich area work outside their council area and with the city's continued growth commutes are bound to increase with all their associated negative side effects, such as pollution, health impacts, and infrastructure construction and maintenance. It is well accepted that mixed land use enables sustainable transport, with its related environmental benefits, and this positively influences individuals' quality of life as well as the efficiency of businesses (Banister 2008). Creating local employment through mixed land use at Swanbank would enable better public transport due to increased demand and increased available tax income. It would also promote active transport – walking and cycling as the distance to the new residential developments would be less than 3 km and existing residential areas are less than 6 km away. Active transport has health benefits and the potential to reduce automobile trips, which have a particularly high carbon intensity (Sallis et al. 2004). Cycling and walking routes could be easily integrated into the new developments and green buffer zones.

4.6.2 Griffith, CSP-single feedstock hybrid

This case study of a proposed 30 MWe CSP–EfB hybrid plant at Griffith, New South Wales, is based on results from a previous biomass resource assessment (Herr et al. 2012). The suitability of the area for such a plant was confirmed by the CSP–EfB resource assessment (see Section 4.2) which identified a cumulative potential of more than 500 MWe for CSP–EfB hybrid plants in the Griffith region. As the resource assessment does not identify specific sites for CSP hybrid plants but only prospective areas, a meeting was organised by the author with Nicola James, Economic Development Coordinator at Griffith City local government area, on 30 May 2013 to visit three potential sites in the area. The site in close proximity to the Tharbogang substation near Griffith (see Figure 40) was subsequently chosen by the author as the substation is scheduled to be upgraded, the area is earmarked for industrial development, and the block of land for the site is owned by the council.

The architecture proposal for this power plant was produced by Kinneth Galang, Master's candidate at the University of Technology, Sydney's School of Architecture, under the supervision of Juliet Landler, a senior lecturer at the school. Galang was supplied with dimensions and constraints in regards to component arrangements by the author and he iteratively produced the plant layouts and renderings for the peer-reviewed publication which is included in Section 4.6.2.1. The paper was presented at the SolarPACES 2013 conference[20] in Las Vegas, USA. The author thanks Kinneth Galang and Juliet Landler for their assistance in this project and for the valuable discussions about power plant architecture.

Figure 40: Potential site for the CSP–EfB hybrid plant near Griffith[21]

[20] www.solarpaces2013.solarpaces.org, accessed 04 April 2014

[21] Map derived from Google Earth, version 7.1.2.2041

4.6.2.1 SolarPACES 2013 conference paper

This conference paper analyses the technical, economic and environmental benefits a CSP–EfB hybrid plant in Griffith could provide and outlines the cost differences between a hybrid plant and a CSP-only plant. The plant is designed to use straw which is expected to be delivered to the plant in bales. The straw bales would be derived from the collected stubble on the fields.

A higher quality process diagram than Figure 3 is provided in the appendix.

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SolarPACES 2013

Solar tower-biomass hybrid plants – maximizing plant performance

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Abstract

Concentrating solar power (CSP)-biomass hybrids plants are becoming increasingly interesting as a low cost option to provide dispatchable renewable energy since the first reference plant commenced operation late 2012, 22.5MWe Termosolar Borges in Spain. The development of such project is a complex task with not only one but two energy sources required to make the project successful. The availability of several studies but only one reference plant worldwide is proof of that.
This paper investigates the hybridisation of a biomass power plant with a molten salt solar tower system. The benefit of this combination is a high cycle efficiency as both the steam generators can provide steam at 525°C and 120bar to the steam turbine. A case study approach is used to provide technical, economic and environmental benefits of a 30MWe CSP-biomass plant with 3h thermal storage in Griffith, New South Wales. At this site such a plant could provide annually 160,300MWh of electricity with an annual average electricity price of AU$155/MWh. Compared to a standalone CSP plant with 15h of thermal storage the hybrid plant investment is 43% lower, providing a possibility to fast-track CSP implementation in countries where CSP is struggling to enter the market due to low wholesale electricity prices, such as Australia.

Selection and peer review by the scientific conference committee of SolarPACES 2013 under responsibility of PSE AG.
Final manuscript published as received without editorial corrections.
Keywords: Solar tower; energy from biomass; hybrid plant

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1. Introduction

CSP-biomass hybrid plants are a well-accepted option to decrease the investment and levelised cost of electricity of CSP plants while increasing power dispatchability. The first reference plant in Spain [1] proves the concept and is likely to enable further installation in high direct normal irradiance (DNI) locations where biomass is also available, such as Australia, India, Greece or Spain.

Several CSP-biomass concepts have been investigated in the past but only the 22.5MWe Termosolar Borges project in northern Spain was built [1]. This shows that the development of such projects is complicated as in addition to all regular project development considerations, such as land availability and network access, not only one but two energy resources have to be abundant in this particular location. While this is a challenge modern geospatial modeling software can help to identify the best sites and allows project developers to not only get a good understanding of the energy resources but also land use, water availability, network access etc.

This paper is based on preliminary geospatial work for CSP-biomass hybrid plants in Australia and outlines the benefits of this concept in a case study in Griffith, New South Wales. The paper provides a technical, economic and environmental analysis for this site and while not all the results are fully transferrable to other sites the concept could be deployed in several regions in Australia and overseas.

2. Current CSP-biomass hybrid concepts

Some early efforts to combine CSP with biomass or waste materials were discussed briefly in the 1980's with dish systems [2]. However, due to technical and financial issues no plants were built. It took another 25 years before construction of the first commercial CSP-biomass hybrid plant commenced near Lleida, ca. 150km west of Barcelona in Spain, see Figure 1. The 22.5MWe Termosolar Borges plant came online late 2012 [1], is located further north than any other CSP project in Spain and uses the mature parabolic trough technology with thermal oil [3]. Several other studies investigated the hybridisation of parabolic trough plants with biomass [4–6] but no other project has commenced construction yet.

Alternatively, Fresnel has been investigated for hybridisation with biomass and waste materials [7–9]. The benefit of using Fresnel would be steam temperatures of up to 500°C [10] and subsequently higher conversion efficiencies. However, no reference plants exist yet.

In addition to live turbine steam other CSP-biomass concepts included the use of CSP for air and feedwater heating as well as external steam superheating from an energy from waste plant [9]. However, none of the concepts considers CSP steam temperatures >430°C which limits the cycle efficiency.

Figure 1: First CSP-biomass plant under construction near Lleida, Spain (left) and biomass fuel (right)

3. Solar tower-biomass hybrid plants

Solar tower systems with direct steam generation and molten salts have the potential to provide steam parameters identical to a biomass plant, >500°C and >100bar, and are according to a recent CSP hybrid assessment the most suitable for hybridisation with biomass [11]. Without thermal storage a direct steam generation would be most favorable while a thermal storage concept would favor a molten salt system. In addition to solar towers with molten salts and DSG systems using a volumetric air receiver are being investigated [12]. However, due to the limited reference situation and the higher complexity of such systems they are more complicated to finance.

In addition to the cost sharing opportunities of hybrid plants in general, such as joint use of steam turbine and condenser, solar tower biomass hybrid plants have the potential to use the required stack to support the receiver. This concept has been investigated for integrated solar combined cycle plants [13] and is also suitable for solar tower-biomass hybrids.

To have a significant solar share in a CSP-biomass hybrid both steam generators have to be able to provide high temperature/pressure steam to the turbine rather than using CSP for feedwater heating or reheat steam (steam reheating is not common in smaller power plants). A CSP-biomass hybrid example is shown in Figure 3.

4. Case study

The case study is based on a CSP-biomass hybrid plant with a total capacity of 30MWe, 15MWe biomass and 15MWe CSP. The CSP component will be modeled as a molten salt and direct steam generation solar tower. Biomass and the aforementioned solar tower references exist for steam temperatures of 525°C at 120bar which provides financiers with investment certainty. Technical reliability is highly important to secure project finance and turn projects into actual power plant installations.

4.1. Methods

Thermoflex version 23.0.1[†] was used for the techno-economic assessment. The software is widely used in academia and industry to model actual solar tower, parabolic trough and Fresnel plants. The software's cost database is used to identify the investment for the different power plant components. With biomass boilers not being a standard Thermoflex component the authors' industry expertise was used to ensure equipment cost accuracy. With an assumed plant commissioning in 2016 the solar field investment is lowered by 10% to reflect 2015 pricing based on a reasonable learning curve [14].

The economic assumptions are a plant lifetime of 30 years, commissioning in 2016, 65% debt finance, a debt interest rate of 8%, a 7% discount rate and an internal rates of return on investment of 11%. The modeling includes capital and operational costs as well as escalation rates for inflation, fuel, electricity and water prices. The investment shown are the owners total project cost consisting of the engineering, procurement and construction price and 9% owner's soft cost covering permits, project management, legal and finance aspects of a power plant project. Network connection is also included. Payback times and net present values derive from the total project cost.

From the different CSP technologies available a solar tower was selected as according to a recent multi-criteria assessment for CSP hybrid plants [11] it is the preferred technology for >500°C hybrid systems. Without thermal storage a direct steam generation tower scores best but due to the integration of 3h thermal storage a molten salt system is preferred as its thermal storage is proven and commercially available from a variety of suppliers.

A water tube boiler with a vibrating grate is selected for the biomass boiler as this is the dominant technology for straw. References exist up to 540°C [15] which matches the CSP parameter well and allows high efficiency power generation.

[†] www.thermoflow.com

The technology selection for a hybrid plant is crucial to obtain finance. This assessment requires the CSP and biomass components to have at least 15MWe reference plants in operation. Both technologies fulfill this criterion with commercial plants in operation, e.g. 20MWe Gemasolar solar tower [16] and 25MWe Sanguesa straw fired power plant [15].

4.2. Site

Griffith in central New South Wales is chosen for the case study as it is a region with strong agriculture and horticulture industries and a DNI of 2,150kWh/m^2/year [17]. From a DNI perspective Griffith is significantly better than Lleida in Spain, 1,800kWh/m^2/year [18], where the first CSP biomass plant commenced operation recently.

A recent study [19] indicates sufficient stubble in this region to provide the 86,000t required annually to fuel a 15MWe biomass plant continuously. The maximum biomass potential in the Mildura region is even higher but the annual biomass yield varies and a conservative approach is important to ensure continuous biomass supply.

The Tharbogang substation near Griffith would require little upgrades to accommodate the output of a 30MWe power plant. The CSP-biomass hybrid plant could follow the daily demand well by providing base-load as well as peak capacity during the day and evening, see Figure 2. This optimises revenue by covering the high price periods.

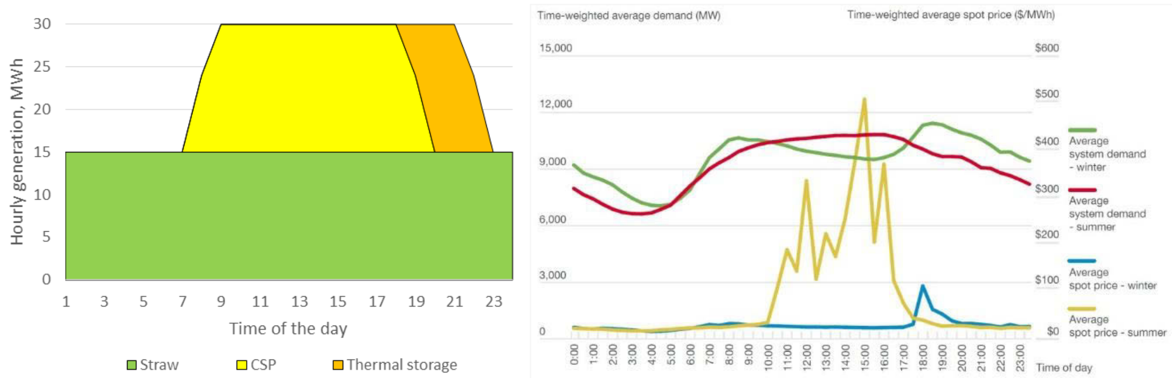

Figure 2: Ideal CSP-biomass generation profile for a 30MWe plant (left) and NSW average weekdays system demand and spot price year ending 2010 (right) [20]

4.3. Technical analysis

Figure 3 shows the process diagram of the proposed hybrid plant with its main components, such as furnace and boiler heating surfaces (1-8), flue gas cleaning (14), stack (18), solar tower with 3h thermal storage (34), molten salt/steam heat exchanger (35-37), steam turbine (19-21, 53, 57), air-cooled condenser (22), feedwater heating system (25-26, 30, 52, 61), and auxiliary equipment.

At full load each steam generator provides 59t/h of steam at 525°C and 120bar to the joint steam turbine generating a net output of 30MWe. Due to the high steam parameters and feedwater heating the plant reaches a net cycle efficiency of 33.4% at full load and 30.2% with only the biomass boiler in operation, see Table 1.

The annual plant output was modeled for the years 2006-10 and the CSP component reached an average annual capacity factor of 29.1% resulting in an average plant output of 160,300MWh. During this period the annual DNI changed resulting in the lowest annual generation in 2010 and highest in 2006, see Table 1. In winter the DNI output decreases significantly while the biomass output increases slightly due to lower ambient temperatures. However, the biomass increase cannot offset the CSP shortfall.

To operate the biomass plant for 8,000h/year a continuous straw supply of 10.74t/h is required. The onsite storage capacity for straw bales is 4 days of full-load operation with the remaining material being stored on the fields where it was harvested. Baling is essential to avoid the material degrading during outdoor storage.

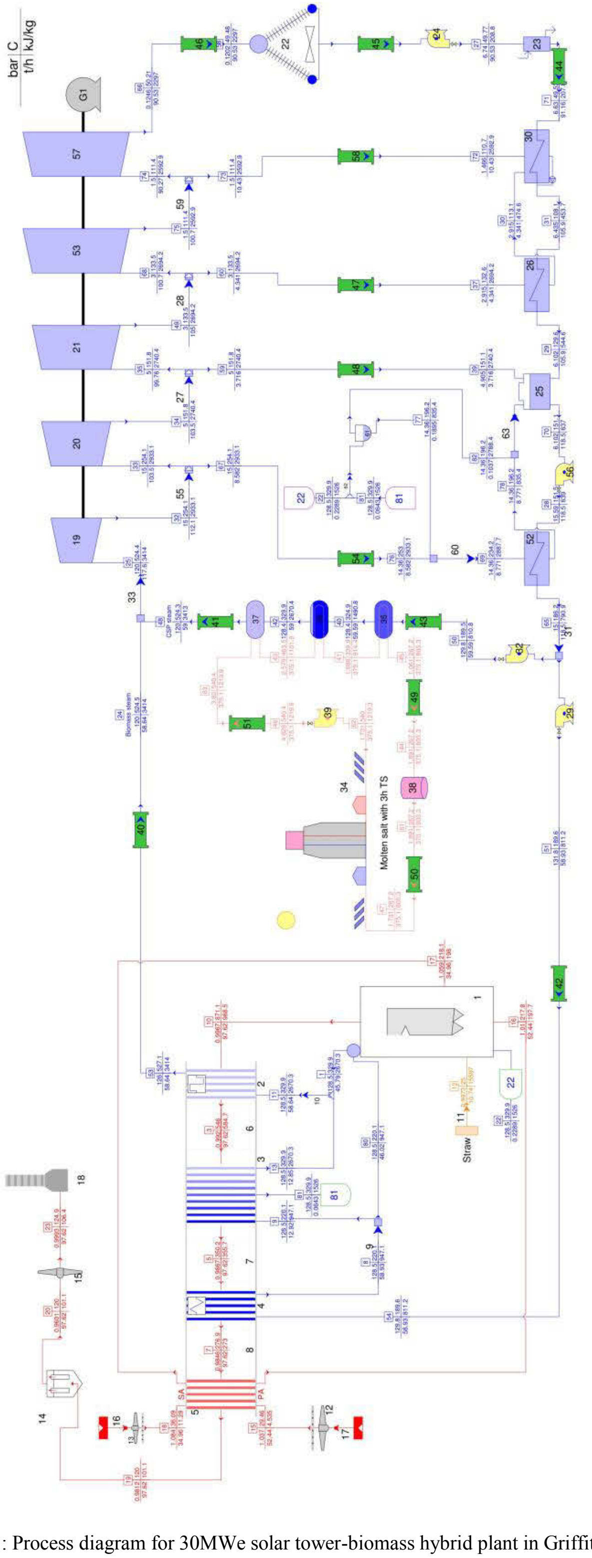

Figure 3: Process diagram for 30MWe solar tower-biomass hybrid plant in Griffith

Table 1: Technical data summary

Total plant capacity	30	MWe
CSP contribution to steam turbine capacity	15	MWe
Biomass contribution to steam turbine capacity	15	MWe
CSP contribution to annual generation (2006-10)	38,300	MWh
Biomass contribution to annual generation (2006-10)	122,000	MWh
Total annual average generation (2006-10)	160,300	MWh
Minimum annual generation (2010)	154,100	MWh
Maximum annual generation (2006)	164,400	MWh
Peak electric plant efficiency (gross)	36.1	%
Net electric plant efficiency	33.4	%
Parasitic losses	7.5	%
Net electric plant efficiency biomass only	30.2	%
Annual straw consumption at 15.6MJ/kg	86,000	t
Plant footprint	74	ha

4.4. Economic analysis

The economic data for the 30MWe CSP-biomass hybrid at Griffith are shown in Table 2. It should be noted that the grid connection, AU$17m, is a significant addition to the plant investment and adds AU$10/MWh to the electricity price. To meet industry typical internal rates of return (IRR) of around 11% an annual average electricity price of AU$155/MWh is required assuming a biomass price of AU$100/t.

The low specific investment for the biomass components, AU$4.2m/MWe, reduces the higher CSP specific investment, AU$7mMWe, to an average of AU$5.6m/MWe while increasing the plant's capacity factor.

Generating the same annual electricity output as the CSP-biomass hybrid would require 26MWe CSP standalone plant with 15h thermal storage (solar multiple of 2.8 and 70% capacity factor). In 2015 such a plant would have a total invest of AU$292m incl. network connection or AU$11.2/MWe. Comparing this with the CSP hybrid results in a 43% cost reduction. The CSP standalone plant would require an annual average electricity price of AU$205/MWh to achieve same IRR.

Table 2: Economic data summary

Plant investment	151	AU$m
Network connection charge	17	AU$m
Specific investment	5.6	AU$m/MWe
Specific CSP investment	7.0	AU$m/MWe
CSP percentage of investment	62	%
Biomass percentage of investment	38	%
Biomass price	100	AU$/t
Net present value	103.7	AU$m
Internal rate of return	10.9	%
Payback	9.5	years
Required annual electricity price	155.0	AU$/MWh

The proposed power station would create 30 positions for plant operators and engineers. Based on literature [21] the additional employment from a biomass power plant can be 10 times higher than the direct employment, e.g. fuel harvesting and logistics. With the Griffith proposal being half CSP and half biomass a factor of 5 has to be assumed for the maximum additional indirect/induced employment. This is still significant for a rural region.

A benefit worth mentioning is the opportunity for local farmers to diversify their businesses as they currently receive annually varying revenues for their crops. A power station would stabilize their revenue stream by making use of a product that is currently considered waste and is, at an expense, burnt in the field.

4.5. Environmental analysis

Both CSP and the biomass are renewable energies which can offset the use of fossils fuels elsewhere in the electricity network. Based on future annual electricity demand and CO_2 emissions trajectories [22] the average annual carbon intensity of Australia's electricity mix between 2016-45 could be 604kg CO_2/MWh. This value seems high but the emissions intensity is expected to stay above 500kg CO_2/MWh until around 2038. Based on this assumption the CSP-biomass hybrid plant could abate up to 2.2 million tonnes CO_2 over its 30 year lifetime. It has to be mentioned that long-term future electricity and CO_2 emissions trajectories contain a high degree of uncertainty, which can be observed currently by a falling rather than increasing electricity demand in Australia.

In addition to avoided CO_2 emissions the use of straw in a power station has further benefits as it can avoid straw burning in the field with its associated particle emissions and subsequent public health impact. The ash collected from the power station could be brought back to the field as it still contains valuable compounds, such as potassium.

4.6. Plant layout and architecture

As the plant stack and receiving tower climbs approximately 70m above the surrounding planar river valley landscape and the conspicuous reflective mirrored heliostats occupy a significant area (72ha), the plant will serve as a significant landmark for the region. Thoughtful consideration to its architecture is essential. Therefore, for the purposes of this study, devising design concepts for the plant was proposed as an assignment for masters students enrolled in subject Advanced Environmental Design at University Technology Sydney (UTS) during the 2013 fall semester. Master student Kinneth Galang developed the preliminary conceptual scheme described below.

For maximum solar power generation, 1,480 heliostats are evenly placed around the central stack in an elliptical shape measuring approximately 1km x 0.9km located on a flat plot of land to the southwest of the intersection of Harward Road and Kidman Way. Walter Burley Griffin used the circle several times in designing Griffith's masterplan and these circles are still prominently evident in city road network today, a continuation of the circular layout was initially considered for the field of heliostats. However as the elliptical layout increases optical efficiency, this variation was determined the superior solution. One road bisects the ellipse to provide a secure main entrance to the central plant. The road then encircles the central plant providing serviceable access to its six main components: fuel storage, the boiler, thermal storage, flue gas cleaning, condenser and the steam turbine, see Figure 4. Of these, the combined stack/receiving tower is the most visible rising above the surrounding buildings and area with a height of 70m, see Figure 5. The fuel storage with its area of approximately 3,100m^2 occupies the most space. While several different configurations of the various components were considered, keeping the stack on the central axis and then clustering the other elements nearby so that distances between the processes could be kept minimal resulted in the most satisfactory solution.

In deference to the agrarian nature of the surroundings, metal siding typical of agricultural buildings was considered most appropriate cladding for the operations. The variation of the building's overall form and detailing of this metal cladding however seek to create a dynamic more consistent with electricity generation. In deference to the local regenerative fuel sources, strawbale infill walls were considered a possibility as a secondary construction system in the more public and visible spaces. The plant complex would include a small public lobby to showcase and explain the technologies being used at the plant. This showroom would be housed next to the main office rooms for the plant and located at the end of the central corridor. In keeping with the circular vocabulary used in the public areas of Griffin, and circular landscaped pool would surround this circular portion of the plant, with the water serving the dual purpose of being the required fire reserve.

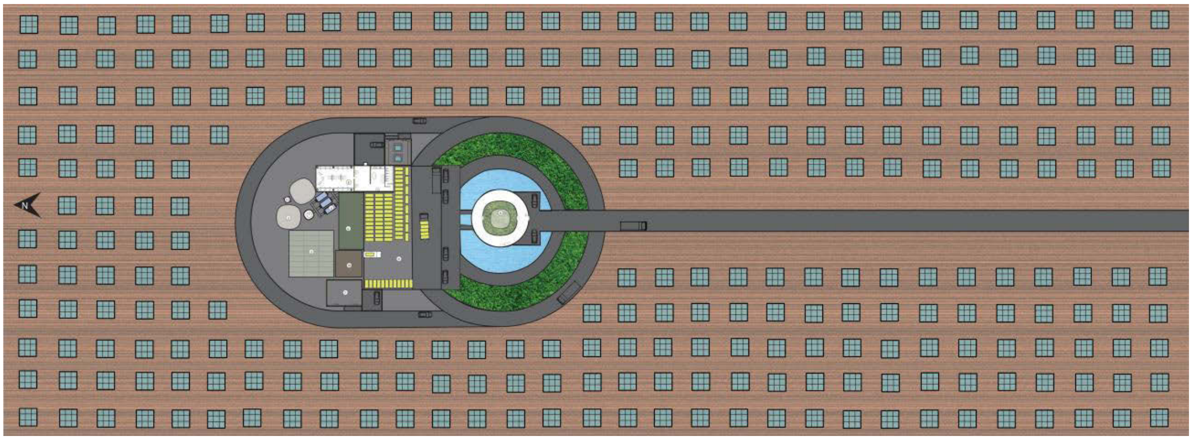

Figure 4: Plan view of the CSP-biomass hybrid plant (heliostat arrangement only schematic)

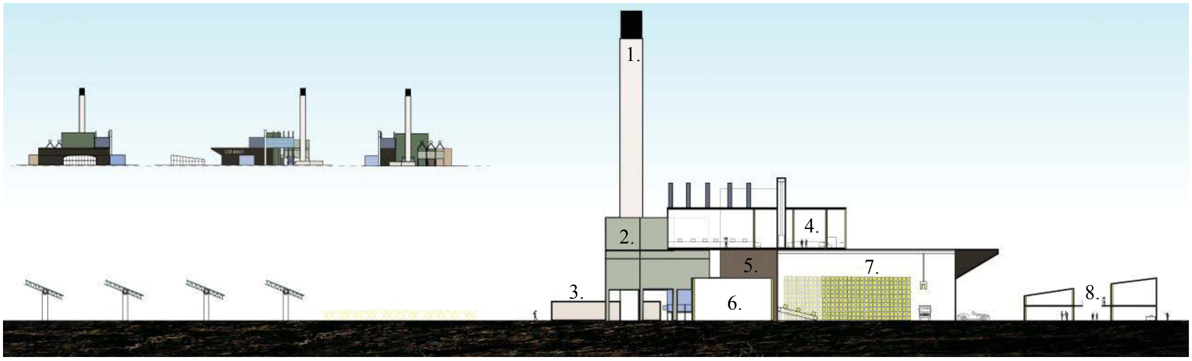

Figure 5: Cross section view of the CSP-biomass hybrid plant; 1. Stack/solar tower, 2. Condenser, 3. Molten salt tanks, 4. Offices, 5. Biomass boiler, 6. Building for auxiliary equipment, 7. Fuel storage, 8. Reception

4.7. Molten salt biomass heater alternative

With 3h thermal storage integrated in the CSP hybrid plant the option of a biomass fired molten salt heater rather than a steam boiler is worth investigating as such a plant configuration could optimise electricity dispatchability with pricing. Currently, there are no references for biomass fired molten salt heaters but significant industry expertise is available for biomass and waste fired thermal oil heaters, which could be used for the design of a molten salt unit, such as fluid circulation, drainability and solidification. To simplify molten salt draining a heater design with vertically arranged heating surfaces, as in the Energy from Waste plant Bamberg in Germany [23], would be ideal. The technical risk of a molten salt heater would be slightly higher compared to a conventional steam boiler but the benefit of shifting electricity output to higher price periods, such as morning peak, makes the concept interesting. A biomass fired molten salt heater would have a lower investment than a steam boiler due to features such as lower working fluid pressure and no drum. However, the molten salt/steam heat exchanger would have to be designed for the total plant capacity and not only the CSP flow which is likely to offset the heater savings.

Typically, electricity prices are lower during the night than the day with peaks in the morning and evening. The evening peak could be covered with CSP charging the thermal storage but the morning period could not. However, with a molten salt biomass heater the plant could operate the steam turbine at minimum load, 7.5MWe, during low electricity price times at night, simultaneously charge the thermal storage and dispatch 30MWe as soon as electricity prices recover in the morning. The biomass fired molten salt unit could also charge the thermal storage during lower DNI winter days to ensure appropriate thermal storage levels to cover the evening peak.

Figure 6 provides an example based on the New South Wales wholesale electricity prices for the 23/07/2012 and the plant's operational strategy to maximize revenue. By diverting thermal energy from biomass to the thermal storage during the 0-5AM low electricity price period and only operating the plant at minimum 7.5MWe load the thermal storage could be charged to 91%. With electricity prices increasing significantly after 5:30AM the thermal storage can be discharged until CSP is able to provide its 15MWe share at 9:30AM. In addition to CSP charging the thermal storage to 48% during the day a biomass fired molten salt heater could further charge the thermal storage from 2-3:30PM to 100%, which allows longer electricity dispatch during the economically attractive evening times. Having the plant online earlier at full load for the morning peak and longer for the evening peak increases the daily revenue by 6.1% compared to a biomass fired steam boiler operating continuously at full load.

With electricity prices fluctuating during the year the economic benefits of a biomass fired molten salt heater are lower at other times. On the 23/01/2013 the New South Wales electricity price was stable at a low level and a molten salt biomass concept could have only capitalized on the small price differences during the night and early morning by charging the TS from 02-4:30AM to 50% and dispatching at slightly higher prices from 5-7:30AM, see Figure 7. The small electricity price differences result in a daily revenue increase of only 0.3%.

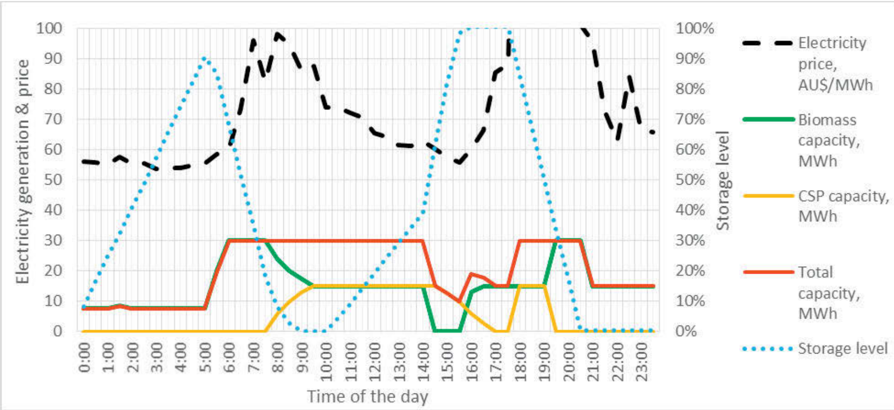

Figure 6: Example of daily electricity generation with molten salt biomass heater in winter (23/07/2012); Peak electricity price at 6:30PM was AU$291.66/MWh

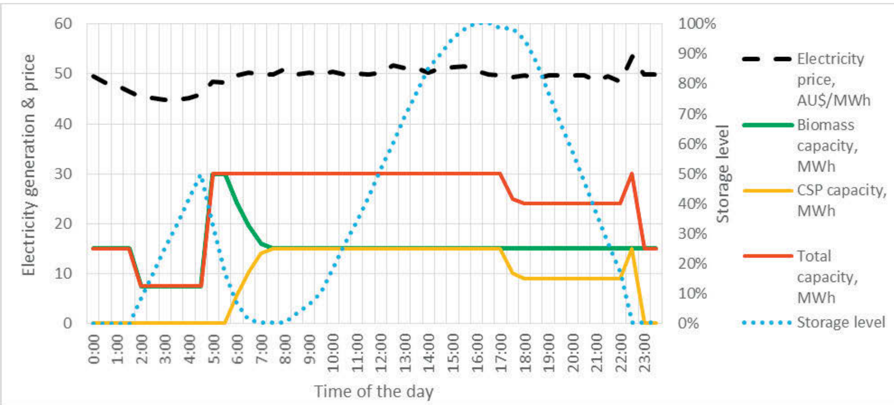

Figure 7: Example of daily electricity generation with molten salt biomass heater in summer (23/01/2013)

5. Conclusion

The combination of a biomass and solar tower energy system is beneficial to maximise the cycle efficiency with proven technologies, which financiers can see operating successfully elsewhere in the world. By combining these two energy sources in Griffith, New South Wales, a power plant could provide lower cost, AU$155/MWh, dispatchable renewable electricity, base-load with additional capacity during the day and evening, as well as additional benefits by avoiding the burning agricultural residues in the field.

Reducing the investment by 43% with a CSP-biomass hybrid plant, compared to standalone CSP, has the potential to fast-track CSP implementation in Australia and familiarize financiers and operators with the different CSP technologies available.

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4.6.2.2 Socio-economic benefits

In line with the higher employment creation of renewable electricity generation compared to fossil fuel fired generation as outlined by Wei et al. (2010) the CSP–EfB hybrid plant proposal at Griffith would lead to a higher employment generation than a coal, natural gas or even wind alternative.

To assess the socio-economic benefits of the Griffith CSP–EfB power station proposal the Input-Output methodology (Ten Raa 2006) was again used. Based on the investment estimate of AU$ 168m, consisting of power plant and network connection costs, 63% or AU$ 105m of the investment is expected to remain in the Australian economy (see Table 4). The cost breakdown assumes plant construction by an Australian-based EPC company. Compared to the Swanbank case study the Australian content is slightly higher, at 63% compared to 58%, due to the larger CSP component, which would be expected to be predominantly manufactured close to the Griffith site. Of the AU$ 105m, a significant percentage is expected to remain the New South Wales and Griffith economies. This would primarily be related to plant construction, equipment installation and some component manufacturing. Overseas manufacturing of major plant items, such as the boiler, steam turbine and condenser system, makes up the remaining 37% or AU$ 63m.

Table 4: Griffith power plant cost breakdown and investment distribution

Cost Breakdown	Investment, AU$m	Australian content, AU$m (%)	Overseas content, AU$m (%)
Turbo generator set	17	3 (20%)	14 (80%)
Boiler system	8	4 (50%)	4 (50%)
Flue gas cleaning	3	2 (60%)	1 (40%)
Solar Field	75	49 (65%)	26 (35%)
Air cooled condenser	10	5 (50%)	5 (50%)
Balance of plant	6	4 (70%)	2 (30%)
Fuel storage facility	6	5 (80%)	1 (20%)
Buildings and roads	18	17 (95%)	1 (5%)
Electricals & controls	8	4 (50%)	4 (50%)
Total plant cost	151	93 (62%)	58 (38%)
Network connection cost	17	12 (70%)	5 (30%)
Total investment	168	105 (63%)	63 (37%)

To assess the overall stimulus of the Griffith plant investment to the Australian economy multiplier factors were used as in the Swanbank case study. A higher value than the biomass electricity multiplier of 1.32 for Swanbank had to be used for Griffith as the setting up of a feedstock supply chain has to be included. A multiplier effect of 1.42 has been used for biomass electricity generation facilities with feedstock procurement (Gan & Smith 2007). Combining this value with the previously used multiplier of 2.3 for CSP (Caldés et al. 2009), and considering the equal 15 MWe EfB and 15 MWe CSP contribution to 30 MWe plant capacity, leads to a combined multiplier effect of 1.86 for the Griffith proposal. This is a 28% higher value than in the Swanbank case study due to the larger CSP component at Griffith and the inclusion of a new feedstock supply chain. Based on the multiplier the direct plant investment would lead to an overall financial stimulus to the Australian economy of AU$ 196m.

The new direct and indirect employment opportunities of the Griffith CSP–EfB hybrid proposal (see Section 4.6.2.1), as well as the local, regional and national financial stimulus the development would provide all support the view that such a plant has the potential to strengthen regional employment, use local renewable energy sources and diversify business opportunities for farmers, both in Griffith and in other regional centres across Australia.

4.7 CSP hybrids as a pathway to a low carbon future

To answer the research question regarding what role CSP–EfB and CSP–EfW hybrid plants can have in Australia's transition to a low-carbon energy future, an analysis of the CSP hybrid niche in the context of the Australian electricity generation market is required. Until recently, this market has been very stable with continuously growing demand and stable market conditions. Coal fired generation has provided the majority of electricity, established market players and qualified personnel. To assess whether CSP–EfB and CSP–EfW hybrid plants are a niche innovation able to support Australia's transition to a low carbon future the two key criteria, mentioned in Section 3.3 about the nature of interaction and the timing of innovation developments have to be addressed.

According to Geels & Schot (2007) the interaction between the niche innovations and landscape developments can reinforce the existing regime, stabilising it and discentivising transitions, or this interaction can disrupt the status quo, applying pressure and incentivising transition. In addition to impact of the niche–landscape interaction on the regime, niche innovations can have a symbiotic relationship with the existing regime that allows their easy adoption as a "*competence-enhancing add-on in the existing regime to solve problems and improve performance*" (Geels & Schot 2007, p. 406). Alternatively, niche innovations aiming to replace the existing regime have a competitive relationship with it, complicating their implementation. Looking at the current Australian electricity generation market using this multi-level perspective the following pressures and relationships emerge:

- Landscape: Landscape pressures on the current electricity regime include: environmental issues such as increased frequency and intensity of disasters; internationally growing political acceptance of the need to respond to anthropogenically induced climate change; more ambitious international greenhouse gas reduction targets such as the 20% European target for 2020 (European Commission 2014); a global upward trend for oil and gas prices; global deployment of renewable energy technologies; rising environmental awareness; and a growing desire to provide a sustainable planet for future generations. The landscape not only applies these pressures to the regime but also to the niches where actors invent suitable solutions.
- Regime: Pressures within the current Australian electricity regime include government policies such as the current Renewable Energy Target (Climate Change Authority 2012)and the carbon pricing mechanism (Australian Government 2011); the unconditional 5% emission reduction target by 2020; scientific consent that greenhouse gas emission reductions are required (Cook et al. 2013); public demand

for lower greenhouse gas emissions; falling electricity demand in recent years; the growing proportion of Australia's energy output provided by intermittent renewable energy generation; the aging of existing generation assets; and rising natural gas and electricity prices. To address these pressures the regime can draw on mature niche innovations, such as various renewable energy technologies, and provide incentives to the niches, such as R&D and technology demonstration grants, to provide further innovations.

- <u>Niche:</u> Incentivised by the aforementioned landscape and regime pressures, various actors in Australia have developed/provided niche innovations ranging from specific energy technologies, including CSP hybrids and intelligent grid systems, to new business models, including energy contracting and community finance. Some of these innovations have been tried and tested overseas, giving them a competitive advantage. They include CSP hybrids and CSP-only plants but also various other innovations, such as intelligent grid systems, and incentives to encourage energy efficiency, community finance, and behaviour change.

In regards to the competitiveness or symbiosis of CSP, EfB and EfW hybrids, some differentiations are necessary. CSP technologies are competitive innovations because in a low carbon/renewable future they aim to replace parts of the regime. New CSP EfB and EfW hybrid plants can be both competitive and symbiotic as they can replace existing generation assets in the regime but can also enhance the regime by solving its problem with the current high cost of CSP. CSP retrofits to existing plants can be considered symbiotic as they are the least-cost means of implementing CSP in the Australian electricity generation market.

From the literature review and the nature of the landscape-regime-niche interactions, it can be assumed that the Australian electricity generation market will undergo a transition in the next two decades. However, is the timing/ maturity of CSP–EfB and CSP–EfW hybrid plants right to take advantage of the window of opportunity that results from the landscape and regime pressures? While technology maturity is debatable, with researchers, technology suppliers, plant operators and financiers all having different perspectives, four criteria have been introduced by Geels & Schot (2007) as reasonable indicators of maturity:

a) *learning processes have stabilised in a dominant design,*
b) *powerful actors have joined the support network*
c) *price/performance improvements have improved and there are strong expectations of further improvement (e.g. learning curves), and*

d) *the innovation is used in market niches, which cumulatively amount to more than 5% market share* (Geels & Schot 2007, p. 405).

Currently, the dominant design with a market share in deployed capacity of 94% of existing CSP plants (IRENA 2012) is the parabolic trough technology. However, in new projects solar tower systems are being deployed at a similar utility scale worldwide. Fresnel is a third design that is also being deployed but with fewer references. Dishes have stabilised in their design principles but are not yet being deployed at a commercial scale. A technology selection process has occurred over the last three decades and it can be concluded that currently one dominant design exists with two new alternatives, solar towers and Fresnel systems, with towers maturing more rapidly than Fresnel systems. The situation for EfB and EfW technologies is similar: combustion systems are currently the dominant design with others maturing. While there is no one dominant design as suggested in criterion 1 of Geels and Schot's list, the availability of few stabilised/mature technologies for CSP–EfB and CSP–EfW hybrid plants provides confidence that the concept can be successfully implemented in the electricity market. The successful CSP–EfB Termosolar project in Spain supports this assumption.

In the past decade powerful actors have joined the CSP industry. They include: well-known EPC contractors such as Alstom, Abengoa, Bechtel and Areva; financiers such as the World Bank, HSBC, Deutsche Bank, and KfW; plant operators such as RWE, NextEra, Florida Power & Light Co., and NRG Energy; research institutes such as NREL in the US, DLR in Germany and CSIRO in Australia; and other institutions such as the International Renewable Energy Agency, the US Department of Energy and the International Energy Agency. The EfB and EfW industry has a longer deployment history, with various powerful actors, including Babcock & Wilcox, Alstom, Hitachi and JFE Engineering. The backing of CSP–EfB and CSP–EfW through such players is demonstrated by the significant Spanish construction company Abantia building the Termosolar plant. With these and other powerful actors engaged in CSP, EfB and EfW projects, Geels and Schot's second criterion is satisfied.

Since the deployment of the first CSP plants in the 1980s the specific costs for CSP fell from AU$ 34m/MWe to around AU$ 6.5m/MWe in 2010 (Hayward, Graham & Campbell 2011) and a recent analysis of various CSP studies (Lovegrove et al. 2012) identified further cost reductions of 10–20% per doubling of cumulative deployment. Through the hybridisation of CSP with EfB and EfW, systems costs can be improved further (see Sections 4.4 and 4.6), which satisfies criterion 3.

CSP is a niche technology used in various markets. The dominant market is electricity generation but other plants operate in markets such as process heating and enhanced oil recovery. In 2014 CSP is expected to provide 0.3% of the world's renewable electricity generation and bioenergy is expected to provide 7.9% (International Energy Agency 2013)[22] Despite CSP being used in various markets it does not fulfil criterion 4, as deployment of commercial plants on a broad scale only started in 2006 in Spain and therefore the technology is not as advanced as others, such as hydro, PV or wind. Also, unlike PV, CSP does not have a small-scale market where new technologies can be tested at lower cost and risk.

In summary this research concludes that CSP technologies for hybridisation with EfB and EfW seem to have sufficient technical maturity to enter the Australian electricity generation market as Geels and Schot's four criteria are fully or partially met. Despite the CSP market share being below the mentioned threshold, the availability of utility scale plants of up to 280 MWe, provides proof that financiers are confident enough to make significant investments in such plants, e.g. US$ 2b for the Solana project (NREL 2014d). The availability of local CSP and CSP hybrid projects at utility scale, including the Termosolar CSP–EfB hybrid plant, is in line with niche management observations shown in Figure 26 on page 53 where at a global level a technology is still a niche but various commercial projects at a local scale exist and demonstrate the innovation's benefits (Geels & Raven 2006). Despite CSP–EfB and CSP–EfW hybrid plants meeting most of Geels and Schot's four criteria a high technical maturity of a certain technology alone is no guarantee for its implementation as other factors, such as policy and social barriers, are highly relevant too, see implementation barrier section 4.5. However, it is a key requirement to convince private and public financiers to engage with and deploy generation assets.

Based on the aforementioned observations it becomes clear that moderate pressures exist within the current Australian electricity generation market which incentivise a transition process by allowing the adoption of sufficiently developed symbiotic innovations. Despite the potential for CSP–EfB and CSP–EfW hybrid plants to replace some regime actors, they are currently considered a symbiotic innovation as they:

a) enable a lower-cost CSP uptake compared to CSP-only plants (Sections 4.4 and 4.6),
b) can generate low-cost dispatchable renewable electricity (Sections 4.4 and 4.6),
c) encounter lower implementation barriers more than CSP-only plants (Section 4.5),
d) have sufficient resources in various Australian states (Section4.2),
e) can enable the uptake of other CSP hybrid plants (Section 4.1),

[22] Percentages are derived from the annual generation figures provided by International Energy Agency (2013)

f) are sufficiently developed (Sections 4.3, 4.4 and 4.6), and

g) can therefore help the Australian Government to meet its renewable energy goals at lower cost while enabling the uptake of a strategically relevant energy technology.

In the narrow context of implementing CSP in the Australian electricity generation market, five features of the SNM steps governments can use to influence a transition (Kemp, Schot & Hoogma 1998) can be identified:

1. Technology choice: The technological features of CSP hybrid and CSP-only plants, particularly mature energy storage, make them, despite currently being more expensive than wind or PV, an attractive option for the federal and state governments to contribute to a stable low carbon electricity generation market in the future. Despite the absence of specific funding pools for CSP, the technology has been supported in the past through funding for research organisations such as ASTRI and big dish research (CSIRO 2013; Lovegrove, Burgess & Pye 2011), for feasibility studies such as the CSP retrofit and Collinsville hybrid study (Australian Renewable Energy Agency 2013a; Meehan 2013), and for demonstration projects such as CSP retrofits to Liddell and Kogan Creek power stations (CS Energy 2011; Novatec Solar GmbH 2012b). This demonstrates that CSP is a desired technology choice.
2. Experiment selection: In addition to small prototype testing of CSP, such as experimental tower in Newcastle (CSIRO 2012) or the single big dish in Canberra (Lovegrove, Burgess & Pye 2011), the testing of CSP at megawatt scale is possible at low risk through its integration into one of the various existing power plants in Australia. A CSP retrofit can utilise existing power plant infrastructure and simultaneously demonstrate its capabilities in daily commercial operation.
3. Experiment set-up: The initial CSP retrofit at Liddell (Mills, Lièvre & Morrison 2003) can be considered an experimental set up. The selected technology provider enjoyed protection through government funding but had to compete with other potential suppliers to reach that stage. Some early selection pressure is vital to allow the best technologies to emerge.
4. Experimental scale up: Subsequent projects, such as the recent CSP expansion at Liddell (Novatec Solar GmbH 2012b) and the CSP retrofit to the Kogan Creek power station (CS Energy 2011), can be considered experimental scale ups as they are based on some results from the original experiment at Liddell. The SolarDawn proposal could also be seen as an experimental scale-up but the capacity of 250

MW and the expected investment of AU$1.2b (Kelly 2012) is very significant which, despite significant government funding, may have contributed to the abandonment of the project. The 40 MWe SolarOasis dish proposal (Regional Development Australia 2011) might be another such example. Hence, the technology scale up has to be significant to prove commercial operation but also needs to be within risk limits for financiers, owners and operators. In Australia the current RET and the carbon pricing mechanism support CSP and other projects, and are drivers contributing to the deployment of commercial scale projects.

5. The breakdown of protection by means of policy: At this point the breakdown of the CSP protection would be detrimental for CSP as the technology has not really started in Australia yet. Once the international and national learning experiences and research efforts lead to lower costs and a CSP uptake, federal and state governments could wind back protection by reducing funding pools for studies and projects, or by introducing of price premiums that are technology and time dependent. However, without a commercial CSP-only plant and with only one operational CSP hybrid, Australia has not reached that stage yet.

Based on these observations some SNM practices to implement CSP can in fact be observed in the Australian electricity generation market and it becomes apparent that CSP hybrid projects have progressed to construction and operation in this context while CSP-only projects have not. Therefore hybridisation seems to be a viable way forward to implement CSP in Australia and CSP–EfB and CSP–EfW can do this at low cost and low carbon emissions from the non-CSP component.

Niche technologies slowly enter a regime through incremental deployment and then up-scale in capacity. Based on the current renewable energy deployment in Australia, some types of renewable energy are closer to entering the Australian electricity generation market than others but all can be considered niche technologies due to their relatively small overall contribution to annual electricity generation. Using the multi-level perspective from Geels & Schot (2007), and considering that currently hydro is Australia's dominant renewable energy contributor, it can be seen that hydro is the technology closest to full regime implementation, followed by wind, bioenergy and PV (Bureau of Resources and Energy Economics 2013). Therefore a future niche technology uptake as shown in Figure 41 is likely.

A future uptake as outlined in Figure 41 would fit with an analysis on the possible Australian energy mix by 2049–50 (Syed 2012) where renewable energy technologies such as wind and solar enter the Australian energy market later than hydro but eventually surpass it due to better resource availability. Similarly, geothermal is expected to grow its market share slowly from currently being non-existent to 8% of Australia's electricity mix in 2049–50. This can be explained through a later technology uptake by the regime due the fact that it is less developed in Australia at this time. Based on Figure 41 CSP is a technology that will experience a later uptake. This is unfortunate as CSP, despite currently involving higher costs than wind and PV, is of significance for Australia's renewable energy future due to the excellent solar resource, the flexible plant capacity range and the proven energy storage capability, which can balance intermittent renewable technologies, such as wind and PV. It is therefore in the country's interest to provide ongoing niche protection for CSP through R&D and project implementation funding.

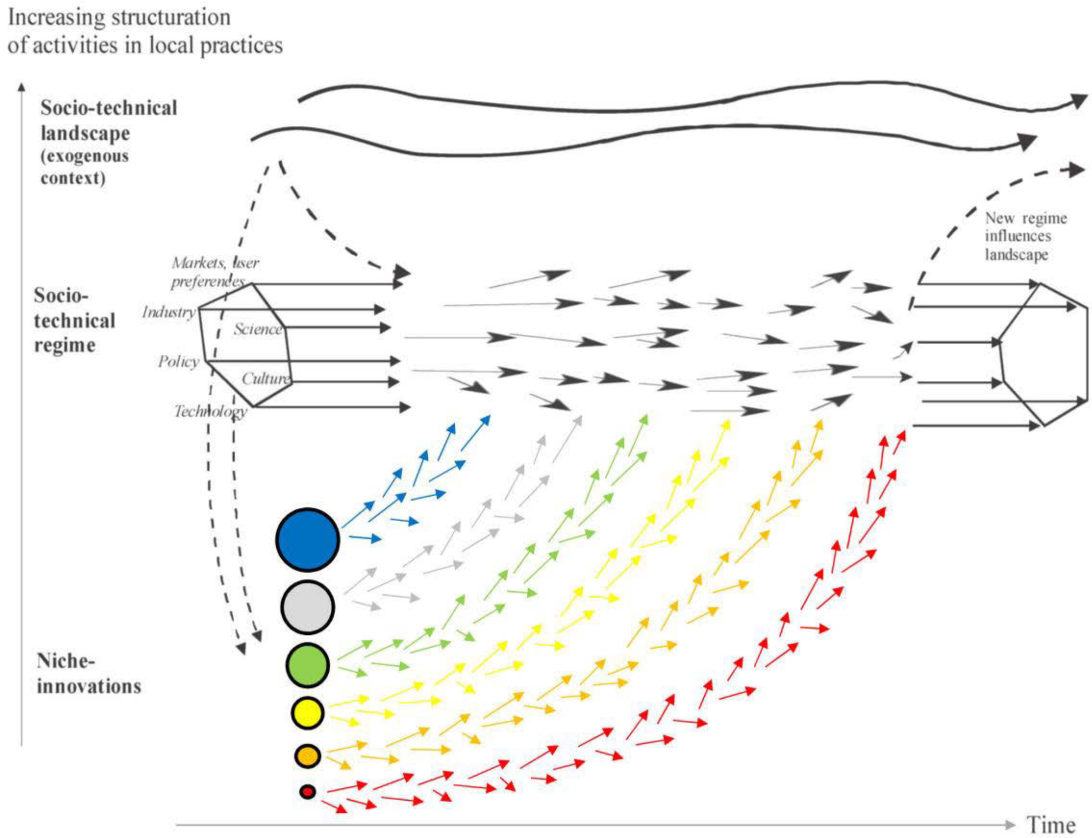

Figure 41: Multi-level perspective for different renewable energy technologies in the Australian electricity generation market; Blue = hydro, grey = wind, green = biomass, yellow = PV, orange = CSP, and red = others; Adapted from Geels & Schott (2007)

To fast-track the CSP uptake and take advantage of the currently moderate pressures within the Australian electricity generation market, several social, technical, economic, environmental and policy barrier reductions are required. As shown earlier CSP–EfB and CSP–EfW hybrid plants can provide these barrier reductions immediately. Figure 42 outlines how the various benefits of CSP–EfB and CSP–EfW hybrid plants could fast-track implementation and in the Australian context the CSP retrofits to the Liddell and Kogan

Creek coal fired power stations support this assumption. These two CSP hybrid projects have progressed towards construction (CS Energy 2011; Novatec Solar GmbH 2012b) while the two significant CSP-only proposals in South Australia and Queensland were unfortunately not able to secure project finance despite significant government grants (Edwards 2013; Kelly 2012).

The accelerated CSP uptake through hybridisation, not only with EfB and EfW systems but with other energy sources as well, would enable technology providers, financiers, plant operators, government agencies, project developers and researchers in Australia to gain local experience with CSP, increase technology confidence, and demonstrate the efficacy of less mature CSP technologies with low financial risk by adding smaller units to existing or new power plants.

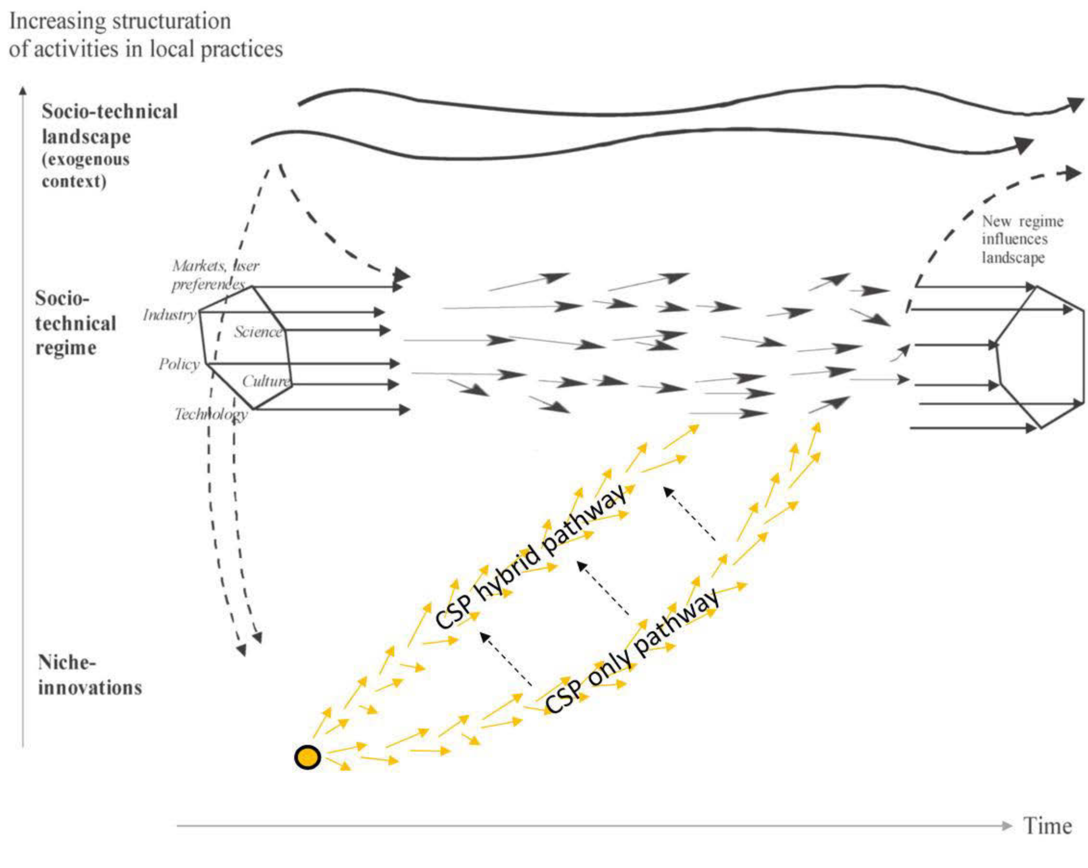

Figure 42: Multi-level perspective for CSP-only and hybrid technologies in the Australian electricity generation market. Adapted from Geels & Schott (2007)

But how could the CSP uptake through hybridisation occur in Australia? The reconfiguration pathway described in Sections 2.6 and 3.3 outlines a plausible process. The pathway provides guidance on how moderate landscape pressure allows the regime to implement some sufficiently developed symbiotic innovations to solve its problems. Initially, the regime remains mostly unchanged, as in the transformation pathway, but over time regime actors explore further combinations and implement more innovations. By doing so, they adjust the basic architecture of the regime. Currently the Australian electricity market is concentrated, with three energy retailers providing the majority of the electricity in the NEM (Hannam 2013), which limits competition. This situation is not unusual and has been acknowledged by transition management researchers who have stated that this poses a threat as

> *large incumbent firms will probably not be the initial leaders of sustainability transitions [however] their involvement might accelerate the breakthrough of environmental innovations if they support these innovations. ... This would, however, require a strategic reorientation of incumbents who presently still defend existing systems and regimes* (Geels 2011, p. 25).

Considering the current situation in the Australian electricity market, a more detailed prospective pathway than the one shown in Figure 42, is needed to accelerate CSP uptake through hybridisation. Such a pathway is shown in Figure 43. The figure is simplified, showing a hypothetical power station scenario and only the technology aspect of the regime. Other aspects of the regime, such as market user preferences, industry, policy, science and culture, are not shown as this would unnecessarily complicate the graph. Initially, the lowest cost CSP hybrid options, being CSP retrofits to existing power stations, are implemented and this process has already started in Australia with the CSP add-ons to the Liddell and Kogan Creek coal fired power stations (CS Energy 2011; Novatec Solar GmbH 2012b). In Figure 43 Liddell power station is shown as 1 and Kogan Creek power station as 2. The Liddell power station is an old unit with a limited remaining lifetime and over time the plant will disappear. It is unlikely that the attached CSP system will remain operational as it is too small to be converted to a standalone plant. While the decommissioning of the CSP plant at Liddell in the foreseeable future might seem a retrograde step, it has served its purpose of demonstrating the technology in a commercial context. In fact the technology for the first stage of the project (Mills, Lièvre & Morrison 2003) was subsequently improved and applied to much larger CSP projects worldwide, for example at the 5 MWe Kimberlina plant in the USA (NREL 2014b), at the 44 MWe equivalent Kogan Creek Solar Boost (CS Energy 2011) and at the 2x 125 MWe Reliance power plant in India (AREVA Solar 2012a). The Kogan Creek coal fired power station is the most modern power station in Australia and is likely to remain in operation with the CSP add-on that is currently under construction for the next several decades as shown with 2 in Figure 43. A third option for an add-on that is capable of eventually replacing an existing coal unit, see 3 in Figure 43, is the retrofit of a solar tower to an existing power plant as such a system could provide steam parameters identical to a coal, gas or oil fired units from the 1980s. Obviously, detailed technical issues such as steam turbine lifetime have to be considered on a project-by-project basis.

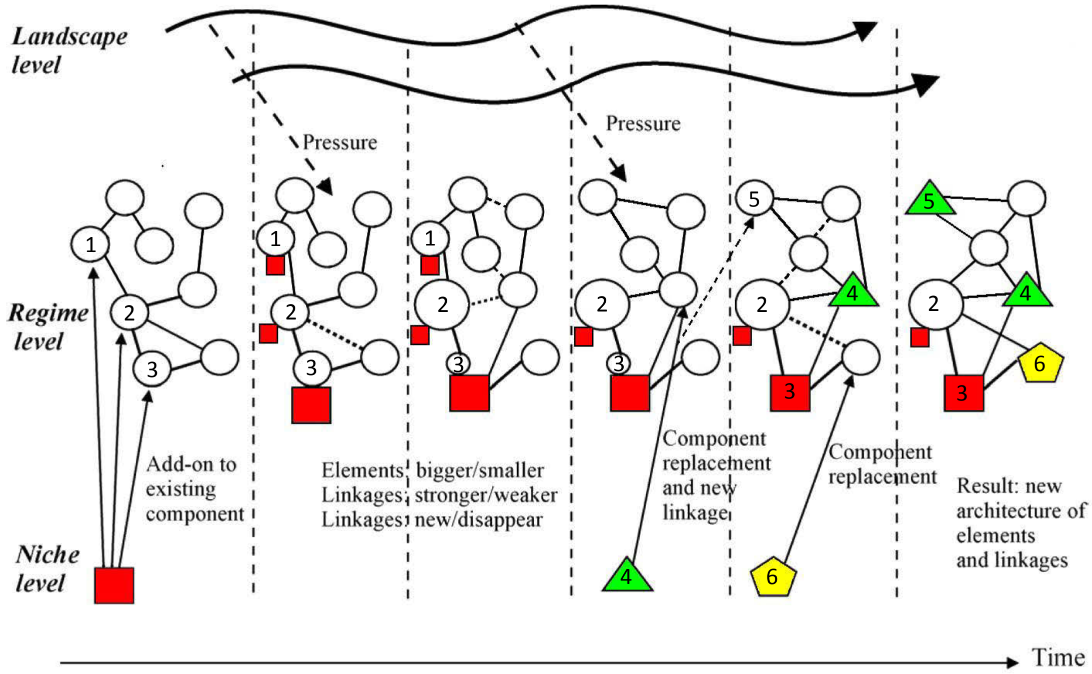

Figure 43: Possible reconfiguration pathway for the implementation of CSP technologies in the Australian electricity generation market; Red squares = CSP add-ons to existing power plants, green triangles = new CSP hybrid plants, and yellow pentagons = new CSP-only plants. Adapted from Geels & Schott (2007).

According to the reconfiguration pathway the first adoption of symbiotic innovations leaves the regime mostly unchanged but the exploration of further combinations leads to the implementation of more innovations and a subsequent adjustment of the regime's basic architecture. The CSP retrofit at Liddell left the Australian electricity generation market basically unchanged but the CSP retrofit to the Kogan Creek power station can be considered an exploration of further combinations and an implementation of more innovations as the plant integrates the solar steam at higher steam parameters into the Rankine cycle systems and is based on design improvements from the initial demonstration plant at Liddell. However, possible CSP retrofits to existing power stations are limited to 16 opportunities in Australia (Meehan 2013) and only retrofitting CSP to fossil fuel assets carries the risk of extended fossil fuel lock-in. The fossil fuel lock-in has been discussed in the context of carbon capture and storage which identified its pairing with biomass as a sustainable long-term path for the technology (Vergragt, Markusson & Karlsson 2011). Similarly, future CSP-fossil fuel hybrids have to be assessed based on their net greenhouse gas abatement potential.

However, with the local CSP experiences gained from first CSP retrofits, regime actors aiming to replace aging infrastructure could explore and implement new CSP hybrids as the next low-cost CSP options (see 4 and 5 in Figure 43). Current proposals for such replacements are the 30 MWe CSP-natural gas study at Collinsville (Australian Renewable Energy Agency 2013a) and the proposed 35.5 MWe CSP–EfB and CSP–EfW hybrid at Swanbank (Ipswich City Council 2012; Peterseim et al. 2012a). The benefits of CSP–EfB and CSP–EfW hybrids over CSP-natural natural gas hybrids include fully renewable power generation, apart from the fossil fuel content in RDF, qualification for more renewable energy certificates, relatively stable fuel prices when using waste materials, and more employment through the feedstock supply chain. At this point in time significant potential exists for CSP–EfB and CSP–EfW hybrid plants using current agricultural and forestry production systems in Australia and first demonstration units, shown as 4 in Figure 43, can pave the way for the deployment of various plants with different capacities across Australia, shown as 5 in Figure 43. Ongoing plant deployment would give component suppliers the confidence to invest in efficient manufacturing infrastructure, upskill staff and lower future production costs rather than going through the uncertain boom and bust cycles that occasional projects create. The cumulative learning from these new CSP–EfB and CSP–EfW, as well as other, hybrid plants can lower costs and increase confidence as well as awareness of CSP in the Australian electricity generation market. Additionally, the learning from CSP–EfB and CSP–EfW hybrid plants in Australia could be transferred to other parts of the world where good solar, biomass and waste feedstock resources are available in the same locations. This would strengthen the awareness of CSP internationally as a reliable renewable energy technology and simultaneously create export opportunities for local companies. The cumulative deployment of, and associated learning with, CSP hybrids in Australia and overseas, as shown in Figure 26 on page 53, would lower CSP costs continuously to a point where actors in the Australian electricity generation market are capable of financing commercial CSP-only plants with thermal storage in locations where CSP–EfB and CSP–EfW hybrid plants cannot be built due to resource constraints, shown as 6 in Figure 43.

The outlined hypothetical CSP implementation pathway describes a plausible transition but transitions are “*so complex with so many uncontrollable factors playing a role that attempts to steer or guide their course will always have an element of tentativeness*” (Elzen, Geels & Green 2004, p. 298). Therefore continuous monitoring, feedback, and adjustments of the transition process are necessary to maximise the likelihood of reaching the desired goal of a sustainable electricity generation market.

Based on the currently moderate landscape and regime pressure in the Australian electricity generation market, its transition from the current fossil fuel dominance to one where CSP plants play a significant role will require the adoption of various symbiotic CSP hybrid technologies. This trend has already started with the construction of two low-cost CSP retrofits to existing coal power plants. The limited retrofit opportunities will lead to new CSP hybrids being the next low-cost CSP option, and depending on the plant location various energy sources exist for CSP hybrids including EfB, EfW and natural gas. The CSP–EfB and CSP–EfW potential in Australia is significant and therefore such hybrids can play a relevant role, but to accelerate CSP deployment and reduce costs as much as possible, additional hybrid configurations have to be embraced considering the net environmental benefits and learning experiences provided by such plants. This highlights that a single promising technical niche innovation, such as CSP–EfB and CSP–EfW hybrids, is not able to commence a transition process but requires interactions and support from the regime and landscape levels, as per transition theory (Schot & Geels 2008). At the regime level this includes current government policies, such as the RET and the carbon pricing mechanism, as well as innovative plant operators and financiers. At the landscape level geopolitical pressure, such as a potential climate agreement at the 2015 UN climate summit in Paris, could accelerate the implementation of sufficiently mature niche innovations, such as CSP–EfB and CSP–EfW hybrid plants.

5 FUTURE RESEARCH

This research is considered to be a comprehensive starting point for CSP–EfB and CSP–EfW hybrid plants in Australia and internationally, and provides the basis for further analysis on this specific combination of energy sources but also other CSP hybrid configurations.

Research building on this PhD thesis could include the investigation of specific policy settings and tools to overcome the barriers identified in Section 4.5. Identifying the optimal policy settings is crucial for the deployment of renewable energy and other technologies and research in this area could identify which policies are required to continue the implementation of CSP hybrids and how these differ to the ones required for CSP-only plants. This work would have to be accompanied by techno-economic analyses to understand the plant cost as well as legislative aspects at the regional, state and federal levels.

Based on the CSP hybrid concepts in Section 4.4, future research could build on this analysis to incorporate new CSP, TES, EfB and EfW technologies and their impacts on hybrid plant efficiency and economic viability. Also, a detailed analysis of the optimal energy storage size based on technology cost improvements and future biomass/RDF feedstock prices would be relevant to better understand future hybrid concepts. New cooling concepts also provide scope for future research including the analysis of air–water hybrid cooling to maximise annual plant output. All these factors would also affect the greenhouse gas abatement potential of CSP–EfB and CSP–EfW hybrids.

The development of CSP technologies is ongoing and the results for the multi-criteria CSP suitability assessment for hybridisation, Section 4.3, are likely to change in the future. Updating this analysis with future CSP data would be interesting not only to identify the most suitable CSP technologies for hybridisation but also the trends that occurred through deployment, research and development.

Future economic modelling could be improved by using actual rather than predicted cost reductions. With additional CSP plant deployment, more accurate CSP costs will be available and these could improve the current modelling. Also of relevance is a more detailed understanding of the construction cost differences for CSP hybrids across Australia. A first analysis identified cost differences for CSP-only plants (Lovegrove et al. 2012) but more detailed work is required and similar work is yet to be done for hybrids. This area of research would require cooperation with an experienced construction company and a more localised geospatial analysis than the one in Section 4.2 to identify the best CSP–EfB and CSP–EfW hybrid plant sites within the identified regions in regards to resource availability and plant construction costs. A future geospatial analysis would have to investigate prospective sites on a local level, not only considering the solid feedstocks and DNI resources available but also additional constraints such as land ownership, other land users, site gradients and transport infrastructure.

Section 4.1 touches on the hybridisation of CSP with natural gas, coal, geothermal power and wind, and each field has scope for further research. Due to the expected long-term growth of natural gas fired generation and resources projects that strongly depend on increasingly expensive natural gas, CSP has the potential to be a valuable fuel saver in areas with sufficiently high solar irradiance. Currently, most CSP hybrid references are with natural gas and in addition to fuel and greenhouse gas savings the operational risk of such plants would be low as the natural gas fired component can ensure redundancy for energy dependent industries at all times. Figure 44 shows that in principle, various mine sites were in good to excellent DNI areas in 2010 and future research could analyse these and new developments in regards to their suitability for the implementation of CSP–natural gas hybrids for process heat and electricity generation. Such research should also analyse the net environmental benefits of new CSP hybrid plants and CSP retrofits to existing natural gas plants.

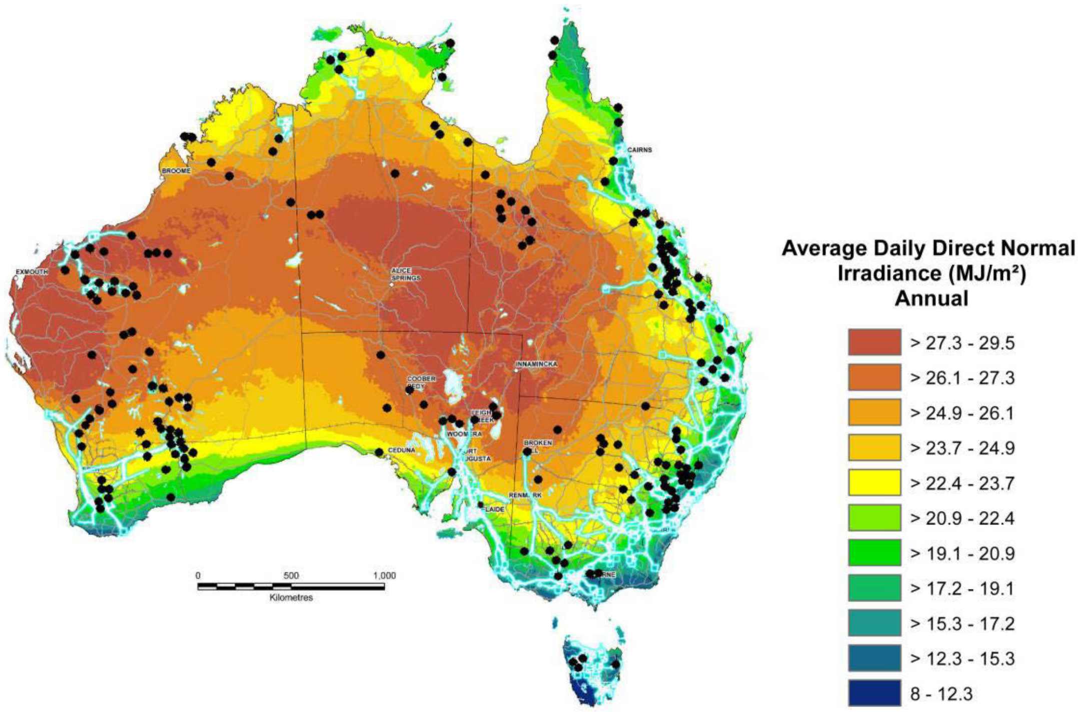

Figure 44: Overlay of DNI (PIRSA Spatial Information Services 2009) with mine sites in Australia (Geoscience Australia 2010)

The high energy cost and high solar irradiance would in some cases increase the prospect of implementing the first CSP plants without government support or with minimal government support. Significant research has been done on retrofitting CSP to coal plants and further research should focus on the plant age and net greenhouse gas savings of such concepts, bearing in mind that that they might extend the operational life of the coal fired unit. In Australia CSP, geothermal and wind resources are available in the some locations and further research into integration concepts, cost and greenhouse gas reductions is required to understand their potential benefits in more detail.

The transition management framework used in this research could also be used to analyse the impact renewable energy plants could have on Australia's transition to a low carbon future. Further research could include a detailed analysis of the timeframe of niche adoptions in the regime and the role of the different regime actors, such as researcher, financiers, operators and technology providers, in the adoption process.

Also of relevance for future research could be the identification of transition pathways that enable a quicker uptake of CSP, and other renewable energy sources in the Australian electricity market, including the identification of the necessary intervention, monitoring and adjustment processes.

6 CONCLUSIONS

Currently, some other renewables, such as PV and wind, are more cost competitive than CSP but CSP is of strategic importance for Australia because the country has one of the best solar resources in the world and because CSP can balance the intermittent renewable generation capacity that is currently being deployed (see Section 2.2). To enable the development of CSP in Australia its hybridisation with EfB and EfW plants and other energy sources offers, among other benefits, an immediate cost reduction pathway (see Section 2.4). However, to deploy such plants in an economically successful manner requires a detailed understanding of the current electricity market (see Section 2.1), energy transition processes and drivers (see Sections 2.6, 3.3 and 4.7), the available technologies (see Sections 2.2, 2.3, 3.2.1.1 and 4.3), technical concepts (see Sections 2.5, 3.2.2.1, 4.1, 4.4 and 4.6), resources (see Sections 2.2.3, 3.2.2.2 and 4.2) and implementation barriers (see Sections 3.2.1.2 and 4.5).

To analyse hybrid plants a categorisation of light, medium and strong hybrids was introduced in Section 4.1 which classifies projects according to the degree of interconnection of the CSP with the additional power generation component such as an EfB or EfW steam system. This categorisation also indicates the level of benefit a CSP hybrid plant can provide, as strong hybrids are able to use more equipment and more capital intensive equipment jointly. Strong hybrids therefore create greater cost synergies than light hybrids that only share a few plant components. The same section expands beyond CSP–EfB and CSP–EfW hybrids and provides a high-level analysis of prospective regions for CSP hybrids with natural gas, geothermal and wind in Australia. All these hybrid combinations have combined resources in Australia, providing a basis for potential deployment in the future.

Separate resource analyses for dedicated CSP and EfB plants were available but to prove that CSP–EfB and CSP–EfW hybrid plants are a viable option in Australia a detailed resource analysis was required to not only identify prospective regions that have sufficiently high DNI and biomass/waste feedstocks, but also to assess the annual electricity output and greenhouse gas abatement potential. Section 4.2 demonstrates that in Australia the states of Western Australia and New South Wales have the highest potential for CSP–EfB and CSP–EfW hybrids but good resources also exist in Victoria, South Australia and Queensland. Most of the identified regions could support 5-40 MWe plants but in proximity to Perth, Brisbane, Adelaide and Canberra in particular, large CSP-multiple feedstock hybrid plants with capacities of up to 270 MWe are possible. The analysis also shows that stubble is the most promising feedstock for CSP–EfB hybrids and such plants could be located across large areas of Australia while wood waste is the dominant fuel for CSP-EfW hybrids and mostly occurs close to population centres. Using all the feedstocks in the identified areas would suffice to generate up to 30.8 TWh of electricity in CSP-single feedstock hybrid plants or 33.5 TWh of electricity in CSP-multiple feedstock hybrid plants. This equals up to 74% of the current 45 TWh renewable energy target and adding mature thermal energy storage can further raise the total electricity potential, for example the figure rises to 40.3 TWh when adding 7.5 h thermal energy storage to all plants. Based on this electricity generation potential and Australia's 2010 average carbon intensity for electricity generation of 841 kg CO_2/MWh, the annual greenhouse gas abatement potential is 27 million tonnes or 4.8% of all Australian 2009–10 emissions. These facts show that the resources for CSP–EfB and CSP–EfW hybrid plants from current agricultural and forestry production systems within proximity to existing transmission infrastructure are significant and worth investigating further.

Given that there is a good resource potential for CSP–EfB and CSP–EfW hybrid plants in Australia, an understanding of the most promising CSP technologies for hybridisation is important. In Section 4.3 various currently available CSP technologies were analysed using a multi-criteria decision-making approach that incorporated quantitative as well as qualitative information. Because of factors relating to the biomass/waste feedstock and the point of CSP integration (such as feedwater heating, reheat steam line or direct turbine steam) solar tower and Fresnel systems with direct steam generation rank best at this time for hybridisation at high steam parameters. This is due to a variety of factors including high steam parameter capability, cost, plant complexity, and good reference situation for smaller plants. The results of the technology ranking process developed and implemented as part of this research matches the actual CSP selection for various hybrid plants already in operation/under construction worldwide and provides a fast but scientifically sound decision-making tool for developers of future hybrid projects. To remain usable in the future, and to solve location-specific technology selection problems, the ranking process is designed flexibly to allow the incorporation of new and site-specific CSP data.

To gain a detailed understanding of the most suitable CSP technologies for hybridisation with EfB and EfW plants, a comparative analysis of the different hybrid concepts was essential to identify the best available at this time. Previous research is available on a few selected CSP–EfB and CSP–EfW hybrid technologies and concepts but in Section 4.4 various scenarios were analysed for two fundamentally different high solar share concepts: a) projects in which the CSP, EfB and EfW steam generators provide identical high pressure/temperature steam to a joint turbine; and b) projects in which biomass and waste feedstocks are used to externally superheat the steam from a conventional parabolic trough plant. The first concept is suitable for areas with significant biomass/waste feedstock resources and allows the independent operation of the CSP, EfB and EfW steam generators while the second concept aims to lower the cost of the mature parabolic trough technology through the use of small quantities of biomass and waste feedstock. However, this does require the simultaneous operation of the CSP, EfB and EfW steam systems. The modelling results for the first concept show that solar tower hybrids reach the highest net cycle efficiency (32.9%), but Fresnel hybrids have the lowest specific investment (AU$ 4.5m/MWe) and they therefore realise the highest internal rate of return. The analysis also reveals that the cost differences between the 17 analysed scenarios vary by up to 31%, which is significant and underlines that the right technology pairing is highly important. CSP hybrids have a 12% lower specific cost than a same capacity CSP-only plants but when comparing plant cost based on the same annual electricity generation, CSP–EfB and CSP–EfW hybrids can be 69% less capital intensive than CSP-only plants as the EfB/EfW component is significantly less capital intensive than solar field or thermal energy storage equipment. The analysis of seven scenarios for the biomass/waste feedstock-fired external superheater concept, applied to a 50 MWe plant with 7.5 h thermal energy storage, shows that depending on the feedstock used, the peak solar to electricity net efficiency increases by up to 10.5% while the specific investment decreases immediately from AU$ 8.2m/MWe to AU$ 6.3m/MWe, a 23.5% reduction. This is significant considering that the CSP industry aims to achieve a 17–40% cost reduction by the end of this decade. Through hybridisation this target could be met immediately.

Despite the significant cost reduction potential through hybridisation, the capital requirement is still a substantial barrier to CSP deployment. However, other social, technical, environmental and policy barriers exist, and knowing them and their importance is important for identifying a pathway for CSP in Australia. Various barriers are identified and analysed in Section 4.5 with a novel assessment of the rating differences between the main barriers for CSP hybrid and CSP-only plants. Four of the top five barriers are identical for CSP-only and hybrid plants. These are: high project capital cost, lack of financial incentives, policy uncertainty, and abundant and subsidised fossil fuels, but on average these barriers are ranked less important for hybrids than for CSP-only plants. While the availability of lower cost renewable alternatives is one of the top five barriers for CSP-only plants it was not rated in the top five barriers for hybrids and replaced by the lack of government policy focus. Workshop participants rated some barriers as being significantly less important for hybrid plants than for CSP-only plants. These barriers included: generation intermittency/lack of energy storage (25% less important), network access, capacity and availability (24% less important), and high project capital/financing costs (19% less important). The barriers with the smallest ranking differences included the lack of codes/standards (1.5% less important for hybrids), inefficient use of back-up fuels (1.6% less important), and resource assessment/knowledge of best sites (2.4% less important). These results support the assumption that CSP hybrids provide more than technical and economic benefits as they also lower relevant policy, social and environmental barriers.

The findings from the various research components have been used in two case studies, (see Section 4.6) to assess the viability of CSP–EfB and CSP–EfW hybrid plants in real business case scenarios. The first case study at the Swanbank landfill in Queensland demonstrates that a 35.5 MWe plant, with 30.7 MWe from EfB and EfW and 4.8 MWe from CSP, could operate highly efficiently on multiple feedstocks, producing not only renewable electricity but also enabling waste diversion from landfill. The proposed plant could deploy the CSP system at 40% lower cost than a CSP-only plant, generate 252,800 MWh of electricity annually with a low carbon intensity of 129 kg CO_2/MWh, abate up to 3.4 million tonnes of CO_2 over its lifetime, and be economically viable within an electricity price range of AU$ 100–120/MWh. The second case study at Griffith in New South Wales investigates a 30 MWe CSP-straw hybrid plant with 3h thermal energy storage, 15 MWe from CSP and 15 MWe from straw. Compared to a CSP-only plant with identical annual generation, the proposal could lower CSP costs by 43%, generate on average 160,300 MWh of electricity annually, abate up to 2.2 million tonnes of CO_2 over its lifetime, and be economically viable with an electricity price of AU$ 155/MWh. Both plants would provide significant socio-economic benefits through higher employment than a fossil fuel fired power generation alternative and stimulation of the local economies, for example through increased local manufacturing and installation of plant components.

With all this information supporting the various benefits of CSP–EfB and CSP–EfW hybrid plants, their potential role and pathway in Australia's transition to a low carbon electricity future had to be analysed (see Section 4.7). The current electricity market is changing due to pressures at various levels, including environmental problems, higher international greenhouse gas reduction targets, current government policies to incentivise renewable energy, and falling electricity demand in recent years. While policy uncertainty is a key concern changes in the electricity market are unlikely to stop due to parallel developments, such as residential roof-top photovoltaic systems and rising natural gas prices. CSP is a strategically relevant technology for Australia's low carbon electricity future and CSP hybrids have the potential to accelerate CSP uptake in the near term. Transition management is a suitable framework to analyse their role and several of its features can be observed in regards to CSP. The technology has been/is being supported through government funding for research, through programs such as the Australian Solar Thermal Research Initiative, feasibility studies such as Collinsville hybrid study, and first experimental plants such as solar towers in Newcastle and a big dish in Canberra. First demonstration plants, such as the original CSP retrofit to Liddell power station, were built and experiment scale-ups can be observed, such as the recent CSP expansion at the Liddell power station and the CSP retrofit to the Kogan Creek power station. While the deployment of CSP-only plants has unfortunately not yet occurred, some CSP hybrid projects have progressed and provide local learning experiences that will be relevant to the future CSP development in Australia. With limited market pressures, a reconfiguration pathway is very suitable for assessing the potential future deployment of CSP in Australia. On this pathway, regime actors adopt symbiotic innovations to solve local problems, and over time, explore and implement further combinations which change the regime. Current and new low-cost CSP retrofits to existing power plants, and the deployment of new CSP hybrid plants, not only with EfB and EfW but with other energy sources as well, have the potential to progressively replace aging electricity generation infrastructure and build local learning and investment confidence to a point where costs have decreased to the extent that it will be feasible to deploy CSP-only plants with a range of generation and energy storage capacities. In Australia CSP–EfB and CSP–EfW hybrid plants, in combination with other renewable energy, energy efficiency and fossil fuel technologies, have the technical, economic and resource potential to transition the electricity market towards a significantly lower carbon intensity and a more sustainable future. The local learnings obtained from current hybrid installations and plants that will be built in the near future will contribute, in combination with growing international experience, to lower technology costs and the progressive deployment of CSP in low-cost wholesale electricity markets. This applies to the Australian market and it is also a model for other countries worldwide.

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APPENDIX

UNIVERSITY OF TECHNOLOGY SYDNEY

Institute for Sustainable Futures

CSP implementation barriers

STEEP analysis

Participant's background	
Technology provider	
Operator	
Consultant	
Researcher	
Government	

Barrier rating		
1	5	9
Not important	Moderately important	Very important

Barrier category	Barrier	Standalone CSP	CSP hybrids
Social	Technology acceptance		
	Lack/quality of information, education and awareness		
	Consumer lack of interest in RE		
	Consumer fear of higher energy prices		
	1		
	2		
	3		
	4		
Technical	Technology maturity		
	Technology complexity compared to other RE, coal and gas		
	Generation intermittency/lack of energy storage		
	Network access, capacity and availability		
	Lack of standards and codes		
	Resource assessments/knowledge of best locations		
	5		
	6		
	7		
	8		
Ecological	Plant footprint/land use		
	Water consumption (cooling & cleaning)		
	Visual impact		
	Inefficient use of back-up fuels		
	9		
	10		
	11		
	12		
Economic	Lack of financial incentives/recognition of externalities		
	High project capital/financing cost and typically large projects		
	Pre-existing investment in existing equipment and infrastructure		
	Abundant and subsidised fossil fuel resources		
	Lower cost renewable energy alternatives		
	13		
	14		
	15		
	16		
Policy	Renewable energy policy uncertainty, e.g. carbon pricing, RET		
	Market concentration limits market and PPA access for smaller developers		
	Lack of coordination at state/national level		
	Complex plant compliance processes		
	Lack of government policy focus		
	Lack of skilled workforce		
	17		
	18		
	90		
	20		

24th June 2013

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5 July 2011

Professor Stuart White
Institute for Sustainable Futures
CB10.11
UNIVERSITY OF TECHNOLOGY, SYDNEY

Dear Stuart,

UTS HREC 2011-208 – WHITE, Professor Stuart, HELLWIG, Professor Dr. Udo, TADROS, Dr. Amir (for PETERSEIM, Mr Juergen, PhD student) – "Carbon emission reduction potential for electricity and process heat generation via nonconventional fuels"

Thank you for your response to my email dated 22/06/11. Your response satisfactorily addresses the concerns and questions raised by the Committee, and I am pleased to inform you that ethics clearance is now granted.

Your clearance number is UTS HREC REF NO. 2011-208A

Please note that the ethical conduct of research is an on-going process. The *National Statement on Ethical Conduct in Research Involving Humans* requires us to obtain a report about the progress of the research, and in particular about any changes to the research which may have ethical implications. This report form must be completed at least annually, and at the end of the project (if it takes more than a year). The Ethics Secretariat will contact you when it is time to complete your first report.

I also refer you to the AVCC guidelines relating to the storage of data, which require that data be kept for a minimum of 5 years after publication of research. However, in NSW, longer retention requirements are required for research on human subjects with potential long-term effects, research with long-term environmental effects, or research considered of national or international significance, importance, or controversy. If the data from this research project falls into one of these categories, contact University Records for advice on long-term retention.

If you have any queries about your ethics clearance, or require any amendments to your research in the future, please do not hesitate to contact the Ethics Secretariat at the Research and Innovation Office, on 02 9514 9772.

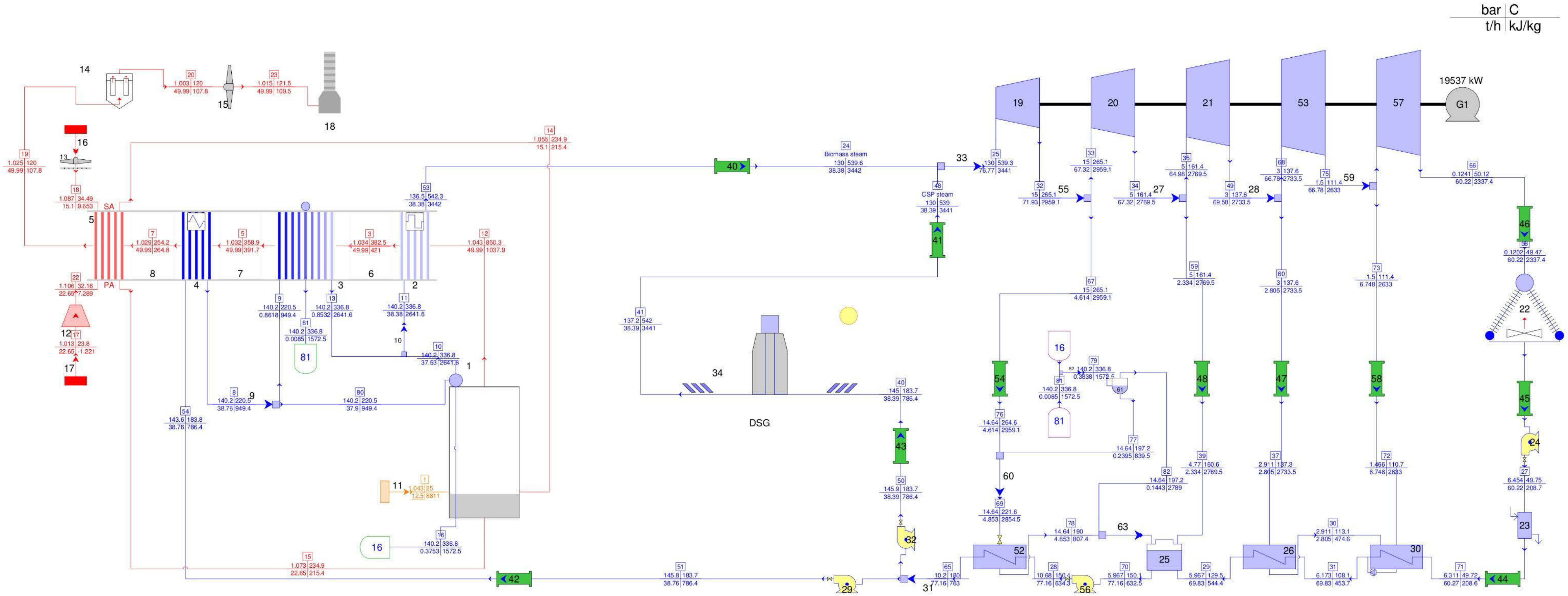
Yours sincerely,

Production Note:
Signature removed prior to publication.

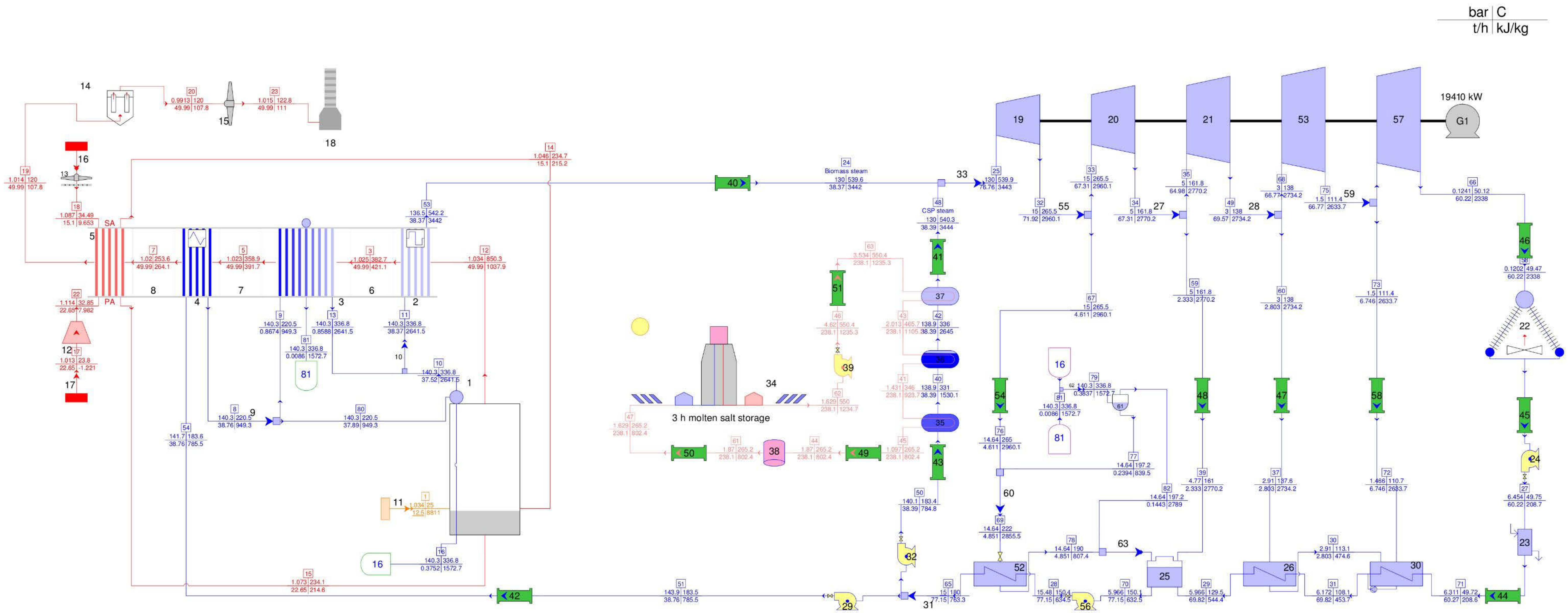
Professor Marion Haas
Chairperson
UTS Human Research Ethics Committee

THINK.CHANGE.DO

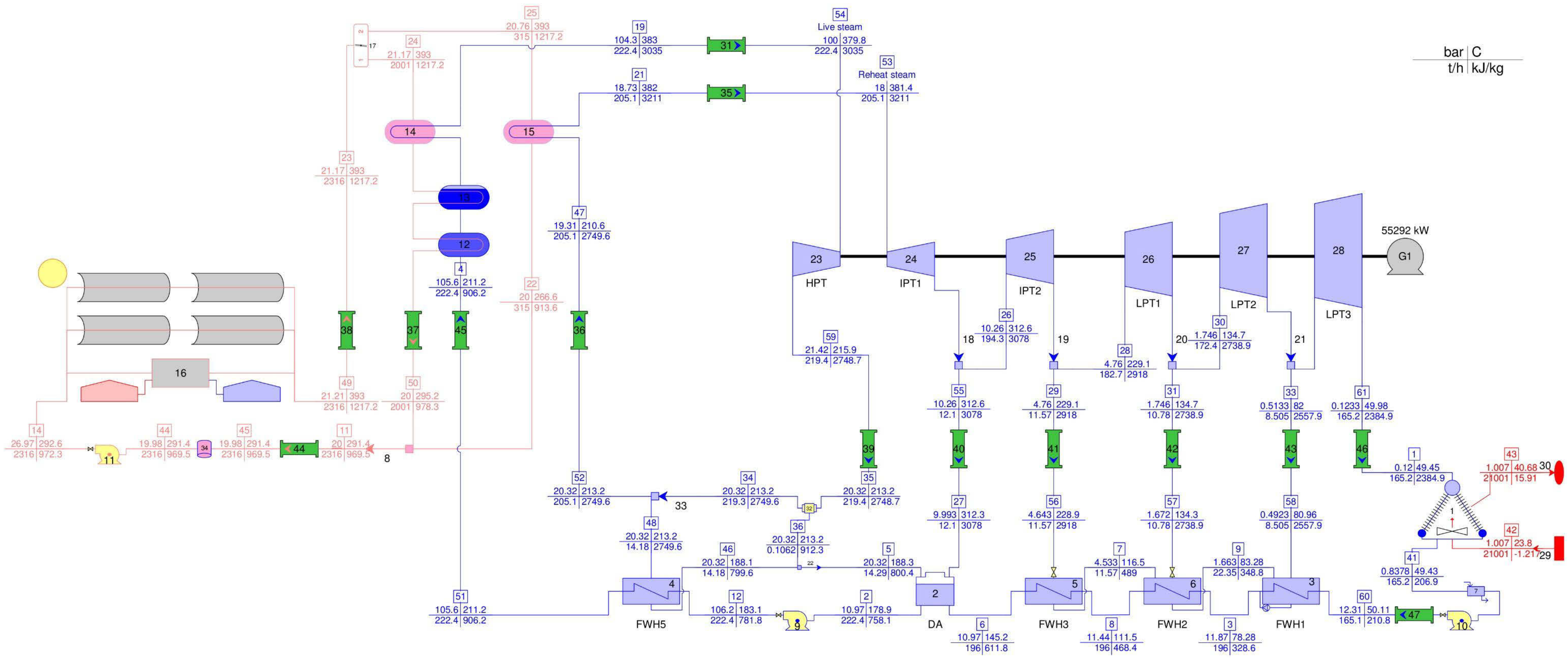
Section 3.4: Ethics clearance from the UTS research ethics committee



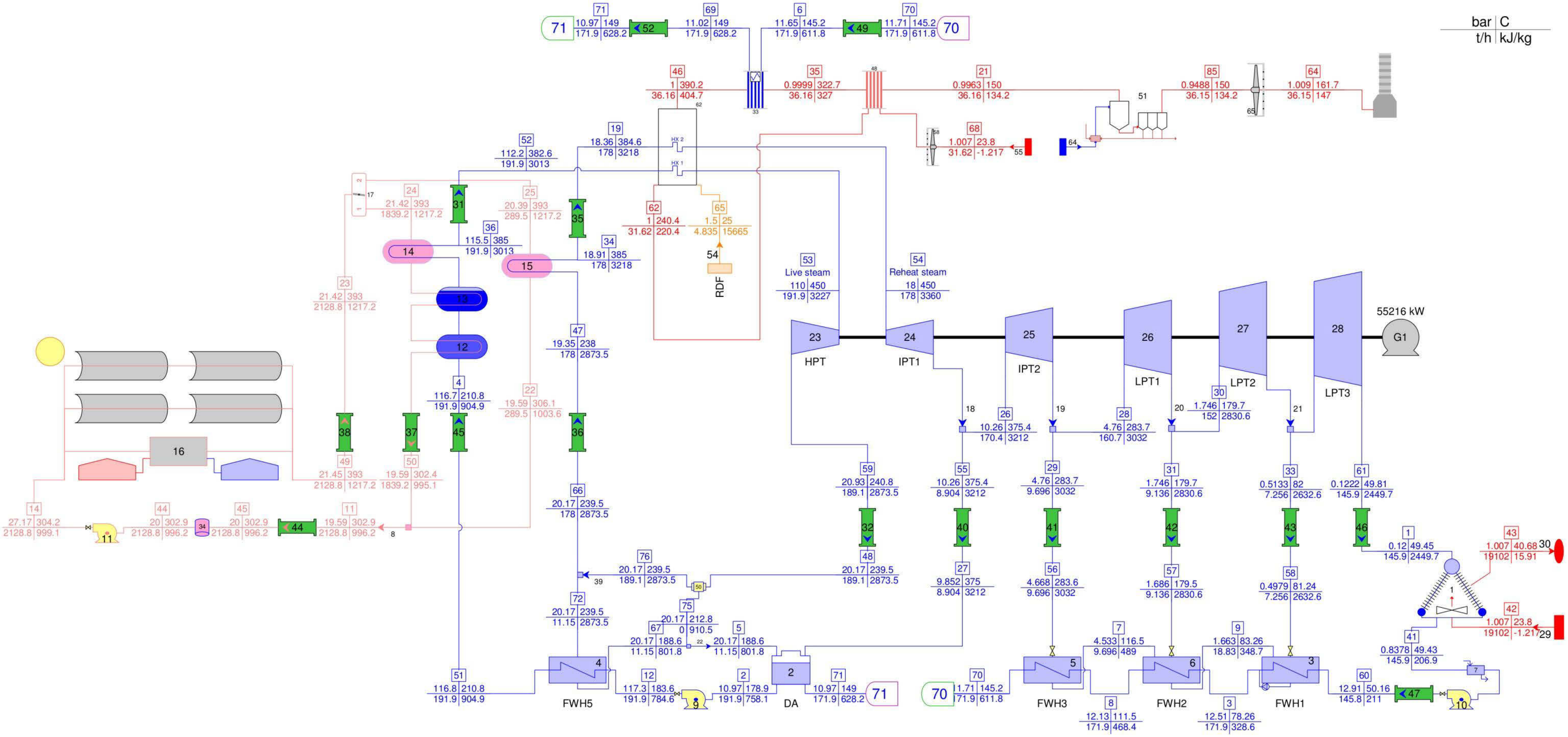
Section 4.4.1: Scenario 16 using a solar tower with direct steam generation



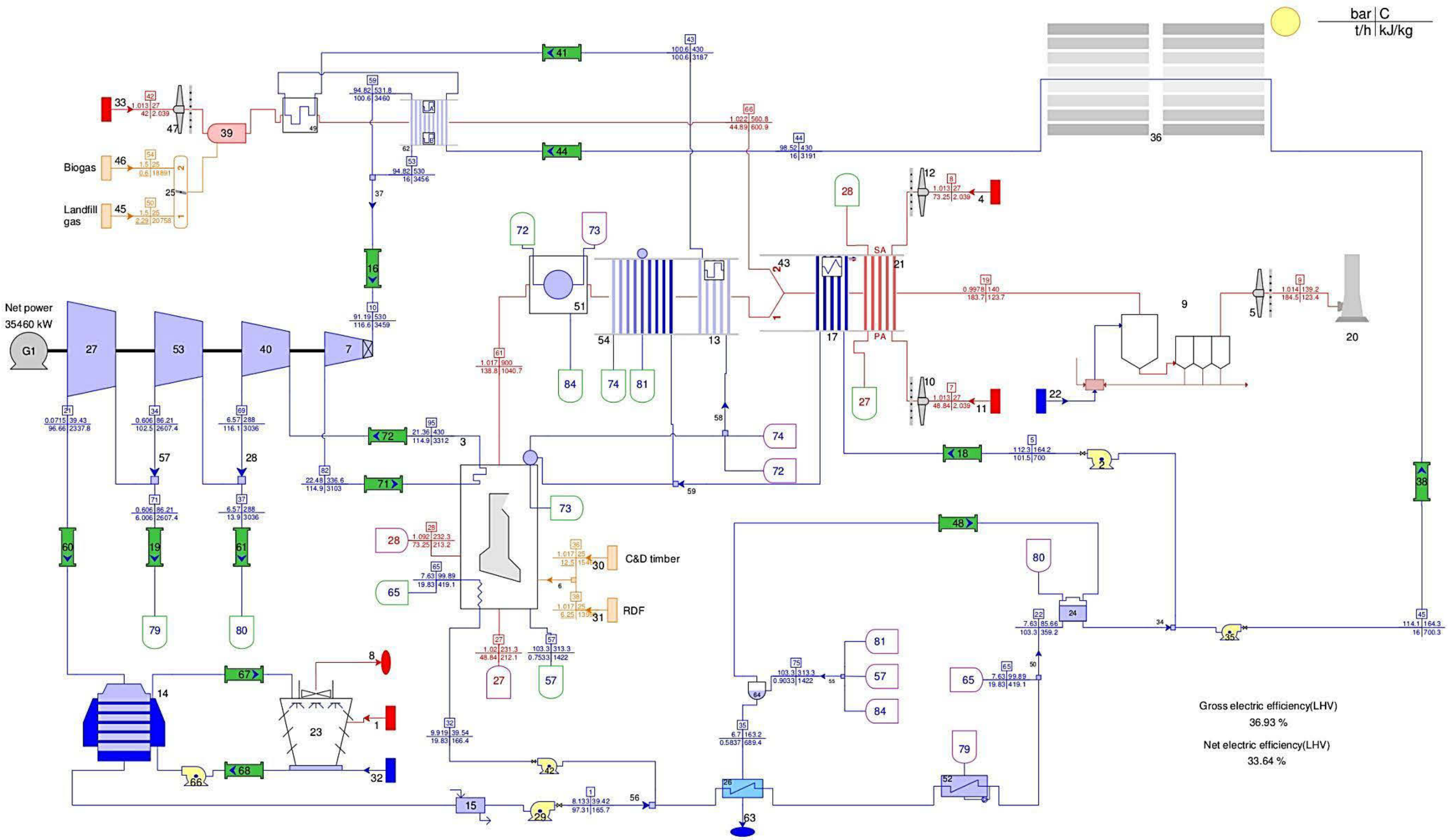
Section 4.4.1: Scenario 17 using a solar tower with molten salt and 3h thermal energy storage



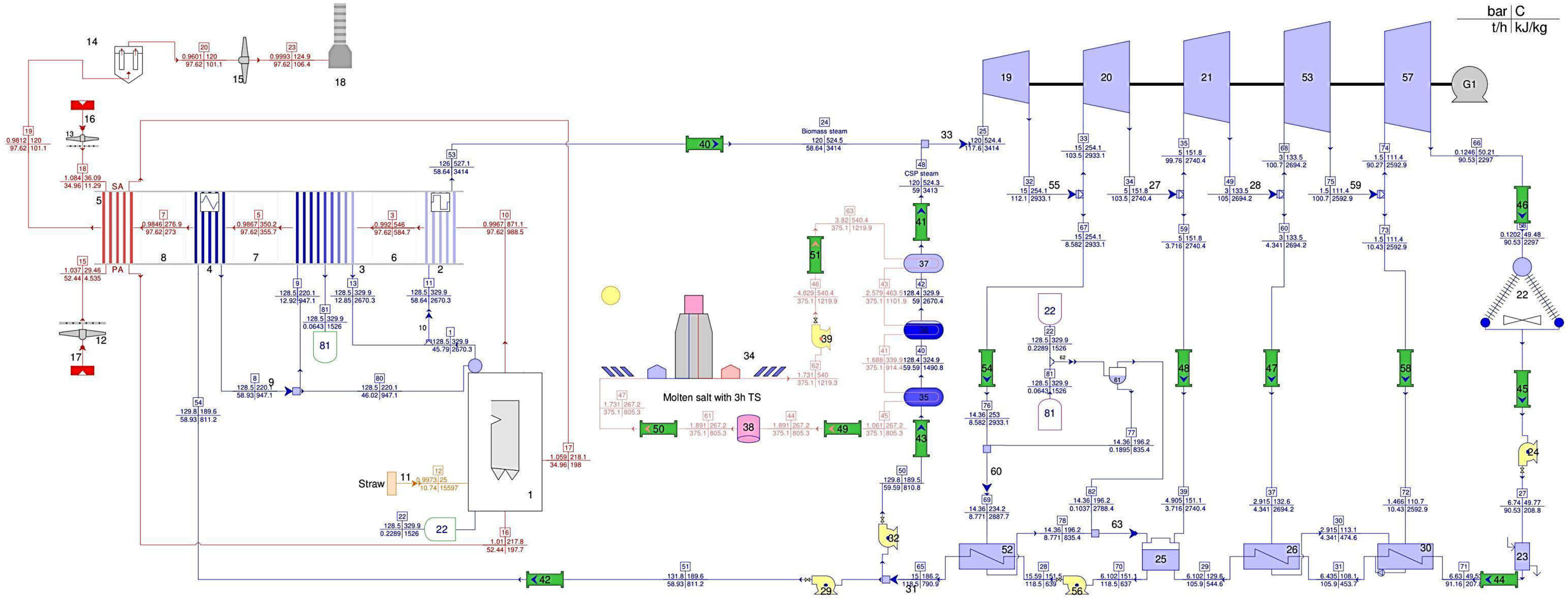
Section 4.4.2: Base case scenario without external steam superheating (Scenario 1 AC)



Section 4.4.2: External superheater concept using RDF (Scenario 3 AC)



Section 4.6.1.1: Process diagram for 35.5MWe (net) Swanbank CSP-multiple feedstock hybrid plant case study



Section 4.6.2.1: Process diagram for 30MWe (net) Griffith CSP-EfB case study